OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **March 1, 2013**

TO:	Phillip Fielder, P.E., Permits and Engineering Group Manager
THROUGH:	Kendal Stegmann, Senior Environmental Manager Compliance and Enforcement
THROUGH:	Phil Martin, P.E., Engineering Manager, Existing Source Permits Section
THROUGH:	Peer Review
FROM:	Tom Richardson, P.E., Existing Source Permits Section
SUBJECT:	Evaluation of Permit Application No. **2012-1393-C PSD** Mid-America Midstream Gas Services, L.L.C. Rose Valley Plant (1311 and 1321) Section 6, T25N, R14W, Woods County Latitude: 36.66771°N; Longitude: 98.75314°W Directions: From the intersection of US Highway 281 (6^{th} Street) and US Highway 64 (Oklahoma Boulevard) in Alva, proceed 9 miles south on US Highway 281, go nearly 5 miles west on E0240 Road, and then turn north into the facility.

SECTION I. INTRODUCTION

Mid-America Midstream Gas Services, L.L.C. (MAMGS) has applied for a permit to construct a new gas plant, the Rose Valley Plant. The new plant will be adjacent to and interconnected with the existing Hopeton Plant. Access Midstream Gas Services, L.L.C. (ACMGS) operates the Hopeton Plant as authorized by Permit No. 2007-247-O (M-1) which was issued on November 23, 2009. The Hopeton Plant was formerly owned and operated by Chesapeake Midstream Gas Services, LLC (CMGS). On July 23, 2012, Chesapeake Midstream Partners, LP was renamed "Access Midstream, LP" and, as a result of this change, CMGS was renamed "Access Midstream Gas Services" (ACMGS). The facilities are collocated and interconnected. Because the two facilities have separate corporate ownerships, each facility will operate under a separate permit. However, emissions from the two facilities will be aggregated to determine the applicability of various regulatory requirements (e.g., Prevention or Significant Deterioration or PSD requirements). This permit authorizes the construction of the Rose Valley Plant and addresses the regulatory requirements associated with the equipment which will be installed at that facility.

At present, the Hopeton Plant includes the following emission sources: two 1,000-bbl condensate storage tanks, one 3.35-MMBTUH hot oil heater, one 3.19-MMBTUH process flare, condensate truck loading, and fugitive sources. The Hopeton Plant is presently classified as a true minor source of criteria pollutants and a true minor source of Hazardous Air Pollutants (HAPs). With the additional equipment authorized by the permit that is the subject of this memorandum, the Rose Valley Plant will be considered to be a PSD major source of Greenhouse Gases (GHGs) and a major source of NOx, CO, and VOCs. The facility will be a synthetic minor source of formaldehyde and total HAPs.

A summary of the new emission sources authorized under this construction permit is presented below:

- Ten 1,775-hp Caterpillar G3606 engines equipped with oxidation catalysts.
- Two 9,443-hp Siemens SGT-200-2S turbines.
- Two 2,889-hp Caterpillar G3520C IM emergency generators with oxidation catalysts.
- Two 5.605-MMBTUH regeneration heaters.
- Two 17.4-MMBTUH hot oil heaters.
- Four 1,000-bbl condensate storage tanks controlled by flares.
- Four 400-bbl produced water tanks.
- Two 20,000-bbl/day amine units.
- Two 2.66-MMBTUH emergency flares.
- One 0.99-MMBTUH enclosed flare.

Additional emissions will be associated with condensate and water truck loading and fugitive emissions.

SECTION II. FACILITY DESCRIPTION

<u>Existing Facility Operations</u> – Hopeton Plant

Natural gas enters the facility and is directed to an inlet separator/slug catcher for removal of free liquids (condensate). The gas stream is directed to a sales pipeline. The condensate is processed by a stabilizer before it is directed to the two 1,000-bbl atmospheric storage tanks. The condensate stabilizer is heated by a 3.35-MMBTUH process boiler. Vapors emitted during the stabilization process are collected and compressed (by an electric compressor) and the compressed vapors are directed to the sales pipeline. Condensate is transported off site by tanker trucks. A 3.19-MMBTUH process flare is installed to receive and combust the contents of process streams during emergencies.

<u>Proposed Facility Operations</u> – Rose Valley Plant

The equipment associated with the Hopteton Plant will continue to operate as described above, except that the gases from the inlet separator and from the stabilizer will be directed to one of the two gas process trains. The following discussion focuses on a single process train, but it should be noted that there will be two process trains operating in parallel.

High pressure gas and liquids from the inlet pipeline will be directed to the inlet separator/slug catcher for separation. Gas from the slug catcher will be directed to a cryogenic processing plant;

liquids will be sent to a condensate stabilizer. A portion of the liquid sent to the stabilizer will be vaporized in the tower and recompressed (with a flash gas compressor) and then directed to the inlet of the cryogenic processing plant. The remaining stabilized liquids will be sent to four 1,000-bbl atmospheric storage tanks. Condensate will then be transported off site by tanker trucks. Working and breathing losses from the condensate storage tanks will be controlled by an enclosed flare.

In the cryogenic processing plant, the gas will be dehydrated and cooled to a low temperature for separation. The separation will yield a very lean residue gas and an ethane-rich liquid product. Residue gas leaving the cryogenic plant will be compressed to pipeline pressure by either engine or turbine-driven compressors. The liquid product will be treated in an amine unit for CO_2 removal. Flash gas from the amine unit will be used as supplemental fuel for the regeneration heater and the still column overhead will be vented to the atmosphere. The treated liquid will be directed to a pipeline for off-site transport and sales.

One 3.19-MMBTUH process flare (currently installed as part of the Hopeton Plant) and two 2.66-MMBTUH emergency flares will receive and combust the contents of process streams during emergencies. A 0.99-MMBTUH enclosed flare will control emissions from the condensate tanks, condensate truck loading, and produced water tanks. It should be noted that the enclosed flare, unlike the emergency flares, will not be equipped with a continuous pilot flame. The feed system to the enclosed flare will include a pressure sensor that opens only when the feed pressure reaches a threshold (typically on at 6 ounces of pressure and off at 2 ounces). When the pressure threshold is reached, a valve will open and the VOC stream will be directed to the flare. An igniter is triggered when the pressure threshold is reached to ensure combustion of the VOC stream. The flare will be equipped with thermocouple/flame detector. The unit will be equipped with a data logger, recording temperature, pressure, and runtime.

Each process train will have a maximum gas processing capacity of 230 MMSCFD for a total, facility-wide capacity of 460 MMSCFD. The facility will only have one operating scenario.

SECTION III. EQUIPMENT

Hopeton Plant – Permit No. 2007-247-O (M-1)

Natural Gas-Fired Heater

EU	Point	Description	MMBTUH	Constr. Date
H-1	H-1	Hot Oil Heater (Hopeton)	3.35	2008

Condensate Tanks [1]

EU	Point	Contents	Barrels	Gallons	Const. Date
TK-1	TK-1	Condensate (Hopeton)	1,000	42,000	2008
TK-2	TK-2	Condensate (Hopeton)	1,000	42,000	2008

[1] Both of these tanks are controlled by a vapor recovery unit.

Process Flare

EU	Point	Emission Unit	Const. Date
FLARE1	FLARE1	Process Flare (Hopeton)	2008

Rose Valley Plant – This Permit

The applicant has organized the emission sources into the 13 Emission Unit Groups (EUGs) identified below. It should be noted that EUG I originally included only the process flare located at the Hopeton Plant. After it was determined that the Hopeton Plant would operate under a separate permit, this EUG was deleted.

EUG A: Natural gas-fired internal combustion engines
EUG B: Natural gas-fired turbines
EUG C: Emergency use natural gas-fired reciprocating internal combustion engines
EUG D: Natural gas-fired heaters
EUG E: Condensate tanks
EUG F: Produced water tanks
EUG G: Condensate truck loading
EUG H: Produced water truck loading
EUG J: Amine units
EUG K: Emergency flares and enclosed flare
EUG L: Fugitive emissions
EUG M: Blowdowns

Equipment specifications and related information on those emission sources are presented (organized by EUGs) in the following tables.

EUG A: Natural Gas-Fired Reciprocating Internal Combustion Engines

EU	Point	Make/Model	hp	Serial #	Mfg. Date [1]
C-1	C-1	Caterpillar G3606LE w/OC	1,775	TBD	TBD
C-2	C-2	Caterpillar G3606LE w/OC	1,775	TBD	TBD
C-3	C-3	Caterpillar G3606LE w/OC	1,775	TBD	TBD
C-4	C-4	Caterpillar G3606LE w/OC	1,775	TBD	TBD
C-5	C-5	Caterpillar G3606LE w/OC	1,775	TBD	TBD
C-6	C-6	Caterpillar G3606LE w/OC	1,775	TBD	TBD
C-7	C-7	Caterpillar G3606LE w/OC	1,775	TBD	TBD
C-8	C-8	Caterpillar G3606LE w/OC	1,775	TBD	TBD
C-9	C-9	Caterpillar G3606LE w/OC	1,775	TBD	TBD
C-10	C-10	Caterpillar G3606LE w/OC	1,775	TBD	TBD

w/OC = with oxidation catalyst
TBD = to be determined
[1] The applicant expects that all of the engines will be manufactured after July 1, 2010.

EUG A: Engine Stack Parameters

Source (make/model)	Height (feet)	Diameter (inches)	Flow (ACFM)	Temp. (˚F)	Fuel (SCFH)
Caterpillar G3606LE w/OC [1]	28	20	12,132	847	13,431

w/OC = with oxidation catalyst

EUG B: Natural-Gas-Fired Turbines

EU	Point	Make/Model [1]	hp	Serial #	Mfg. Date [2]
T-1	T-1	Siemens SGT-200-2S	9,443	TBD	TBD
T-2	T-2	Siemens SGT-200-2S	9,443	TBD	TBD

TBD = to be determined.

[1] Neither of these turbines is equipped with post-combustion controls.

[2] The applicant expects that the turbines will be manufactured after February 18, 2005.

EUG B: Turbine Stack Parameters

Source (make/model)	Height (feet)	Diameter (inches)	Flow (ACFM)	Temp. (˚F)	Fuel (SCFH)
Siemens SGT-200-2S	49	56	128,504	925	77,840

EUG C: Emergency Use[1] Natural Gas-Fired Reciprocating Internal Combustion Engines

EU	Point	Make/Model	hp	Serial #	Mfg. Date [2]
GEN-1	GEN-1	Caterpillar G3520C IM w/OC	2,889	TBD	TBD
GEN-2	GEN-2	Caterpillar G3520C IM w/OC	2,889	TBD	TBD

w/OC = with oxidation catalyst

TBD = to be determined

[1] These engines are authorized for 750 hours of operation per year. Therefore, they are more appropriately described as "limited use engines."

[2] The applicant expects that all of the engines will be manufactured after January 1, 2008.

EUG C: Engine Stack Parameters

Source (make/model)	Height (feet)	Diameter (inches)	Flow (ACFM)	Temp. (˚F)	Fuel (SCFH)
Caterpillar G3520C IM w/OC	30	14	17,348	893	20,376

w/OC = with oxidation catalyst

EUG D: Natural Gas-Fired Heaters

EU	Point	Description	MMBTUH	Const. Date [1]
H-2	H-2	Regeneration Heater	5.605	TBD
H-3	H-3	Hot Oil Heater	17.4	TBD
H-4	H-4	Regeneration Heater	5.605	TBD
H-5	H-5	Hot Oil Heater	17.4	TBD

TBD = to be determined.

[1] The applicant expects that heaters H-3 and H-5 will be manufactured after June 9, 1989.

EUG E: Condensate Tanks [1]

EU	Point	Contents	Barrels	Gallons	Const. Date
TK-3	TK-3	Condensate	1,000	42,000	TBD
TK-4	TK-4	Condensate	1,000	42,000	TBD
TK-5	TK-5	Condensate	1,000	42,000	TBD
TK-6	TK-6	Condensate	1,000	42,000	TBD

TBD = to be determined.
[1] Each of these tanks will be controlled by an enclosed flare.

EUG F: Produced Water Tanks [1]

EU	Point	Contents	Barrels	Gallons	Const. Date
WTK-1	WTK-1	Produced Water	400	16,800	TBD
WTK-2	WTK-2	Produced Water	400	16,800	TBD
WTK-3	WTK-3	Produced Water	400	16,800	TBD
WTK-4	WTK-4	Produced Water	400	16,800	TBD

TBD = to be determined.
[1] Each of these tanks will be controlled by an enclosed flare.

EUG G: Condensate Truck Loading [1]

EU	Point	Name	Throughput (gal./yr)
CL-1	CL-1	Condensate Truck Loading	4,599,000
CL-2	CL-2	Condensate Truck Loading	4,599,000

[1] Condensate tank loading will be controlled by an enclosed flare.

EUG H: Produced Water Truck Loading

EU	Point	Name	Throughput (gal./yr)
WL-1	WL-1	Produced Water Truck Loading	153,000
WL-2	WL-2	Produced Water Truck Loading	153,000

EUG I [Deleted]: Process Flare – This EUG was eliminated once the determination was made that the Hopeton Plant would operate under a separate permit.

EUG J: Amine Units

EU	Point	Description	Throughput (bbl/day)	Const. Date
AMINE-1	AMINE-1	Amine Unit	20,000	TBD
AMINE-2	AMINE-2	Amine Unit	20,000	TBD

TBD = to be determined.

EUG K: Emergency Flares and Enclosed Flare

EU	Point	Emission Unit	Const. Date
FLARE2	FLARE2	Emergency Flare	TBD
FLARE3	FLARE3	Emergency Flare	TBD
EFL-1	EFL-1	Enclosed Flare	TBD

EUG L: Fugitive Emissions

EU	Point	Number	Type	Service	Const. Date [1]
FUG	FUG	616	Valves	Gas	TBD
		14	Relief Valves	Gas	TBD
		10	Compressor Seals	Gas	TBD
		1,232	Flanges	Gas	TBD
		400	Valves	Light Oil	TBD
		800	Flanges	Light Oil	TBD
		8	Pump Seals	Light Oil	TBD
FUG2	FUG2	616	Valves	Gas	TBD
		14	Relief Valves	Gas	TBD
		10	Compressor Seals	Gas	TBD
		1,232	Flanges	Gas	TBD
		400	Valves	Light Oil	TBD
		800	Flanges	Light Oil	TBD
		8	Pump Seals	Light Oil	TBD

TBD = to be determined.

[1] Some of this equipment was installed in 2008 at the Hopeton plant. The values shown in this table represent the suite of items needed for both process trains.

EUG M: Blowdowns

EU	Point	Name	Throughput (scf/yr)
BD	BD	Engine-Driven Compressor Blowdowns	5,853,096
BD2	BD2	Turbine Blowdowns	1,618,984

SECTION IV. PSD REVIEW

For the purposes of determining the applicability of Prevention of Significant Deterioration (PSD) requirements, emissions from both the Hopeton Plant and the Rose Valley Plant have been combined. The construction activities which are the subject of this permitting action will result in facility-wide (both facilities combined) potential emissions of Greenhouse Gases (GHGs) in excess of the PSD major source threshold of 100,000 TPY of carbon dioxide equivalent (CO_{2e}). Since the facility will be a PSD major source, this permitting action must include a PSD review. This permitting action will also result in increases in emissions in excess of PSD significance thresholds for the following pollutants: NOx, CO, VOC, $PM_{2.5}$, and CO_{2e}. Evaluation of ozone will also be required.

Any increase of emissions must be evaluated for PSD if they exceed a significance level (100 TPY CO, 40 TPY NO_X, 40 TPY SO_2, 40 TPY VOC, 15 TPY PM_{10}, 10 TPY $PM_{2.5}$, and 10 TPY H_2S).

A. Project Emission Increases

The project will result in the construction of a new PSD major stationary source collocated with an existing minor source. Emissions from both the existing source and the new source are aggregated for this analysis. This project must undergo Best Available Control Technology (BACT) analysis and modeling for all pollutants which the facility has the potential to emit (PTE) in significant amounts. PTE means the maximum capacity of a source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is enforceable. Secondary emissions do not count in determining the potential to emit of a source.

The table on the next page presents the PTE authorized by this permit. The PTE associated with the proposed permitting action is aggregated by Emission Unit Group (EUG); subtotals for each pollutant are also provided. The PTE for each individual unit is presented and discussed later in this section.

Since the project results in significant emissions of NO_X, CO, O_3 (for VOC and NO_X), $PM_{2.5}$ (for direct $PM_{2.5}$ and NO_X), and CO_{2e}, this project is subject to PSD and the applicant is required to apply BACT to each emission unit at which a net increase in the pollutant would occur, to conduct a facility air quality impact analysis for each regulated pollutant that exceeds the significant emission increase threshold, and to perform monitoring, if applicable. There are currently no applicable modeling or monitoring requirements for CO_{2e}.

Potential to Emit/Project Emission Increases [1]

	NO_X	CO	VOC	SO_2	$PM_{10}/PM_{2.5}$	CO_{2e}
EUG	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**
A: Engines	85.70	61.10	28.30	0.30	5.30	76,402
B: Turbines	39.12	23.82	25.00	2.18	4.20	74,932
C: Emergency Engines	2.38	2.04	2.64	<0.01	<0.01	2,302
D: Heaters [2]	11.22	19.35	1.27	0.15	1.76	25,296
E: Condensate Tanks [2]	--	--	0.82	--	--	--
F: Prod. Water Tanks	--	--	<0.01	--	--	--
G: Cond. Loading	--	--	7.06	--	--	9
H: Water Loading	--	--	0.02	--	--	1
Process Flare [2]	0.09	0.39	0.36	<0.01	<0.01	149
J: Amine Units	--	--	14.78	--	--	16,233
K: Emergency Flares	2.42	10.69	1.23	0.03	<0.01	4,317
L: Fugitive Emissions	--	--	13.78	--	--	647
M: Blowdowns	--	--	21.22	--	--	2,929
Totals (PTE)	**140.93**	**117.39**	**116.48**	**2.66**	**11.26**	**203,217**
SER	**40**	**100**	**40**	**40**	**15/10**	**75,000**
>SER	**YES**	**YES**	**YES**	**NO**	**NO/YES**	**YES**

[1] Potential emissions due to this permitting action include emissions from both the Hopeton Plant (existing) and the Rose Valley Plant (new construction).

[2] EUGs D and E include potential emissions from equipment items located at the Hopeton plant. The Process Flare is also located at the Hopeton Plant.

B. BACT

BACT shall apply to each emissions unit for each pollutant that is significant. The following EU are subject to the BACT requirements:

Point	Emission Unit	NO_X TPY	CO TPY	VOC TPY	$PM_{2.5}$ TPY	CO_{2e} TPY
C-1	1,775-hp Caterpillar G3606LE	8.57	6.11	2.83	0.53	7,640
C-2	1,775-hp Caterpillar G3606LE	8.57	6.11	2.83	0.53	7,640
C-3	1,775-hp Caterpillar G3606LE	8.57	6.11	2.83	0.53	7,640
C-4	1,775-hp Caterpillar G3606LE	8.57	6.11	2.83	0.53	7,640
C-5	1,775-hp Caterpillar G3606LE	8.57	6.11	2.83	0.53	7,640
C-6	1,775-hp Caterpillar G3606LE	8.57	6.11	2.83	0.53	7,640
C-7	1,775-hp Caterpillar G3606LE	8.57	6.11	2.83	0.53	7,640
C-8	1,775-hp Caterpillar G3606LE	8.57	6.11	2.83	0.53	7,640
C-9	1,775-hp Caterpillar G3606LE	8.57	6.11	2.83	0.53	7,640
C-10	1,775-hp Caterpillar G3606LE	8.57	6.11	2.83	0.53	7,640
T-1	9,443-hp Siemens SGT-200-2S	19.56	11.91	12.50	2.10	37,466
T-2	9,443-hp Siemens SGT-200-2S	19.56	11.91	12.50	2.10	37,466
GEN-1	2,889-hp Caterpillar G3520C IM	1.19	1.02	1.32	<0.01	1,151
GEN-2	2,889-hp Caterpillar G3520C IM	1.19	1.02	1.32	<0.01	1,151
H-2	5.605 MMBTUH Regen. Heater	1.18	2.20	0.14	0.20	2,895
H-3	17.4 MMBTUH Hot Oil Heater	3.65	6.82	0.45	0.62	8,917
H-4	5.605 MMBTUH Regen. Heater	1.18	2.20	0.14	0.20	2,895
H-5	17.4 MMBTUH Hot Oil Heater	3.65	6.82	0.45	0.62	8,917
TK-3	1,000-bbl Condensate Tank	---	---	0.14	---	---
TK-4,5,6	Three 1,000-bbl Condensate Tanks	---	---	0.41	---	---
WT-1,2	Two 400-bbl Produced Water Tanks	---	---	<0.01	---	<1
WT-3,4	Two 400-bbl Produced Water Tanks	---	---	<0.01	---	<1
CL-1	Condensate Truck Loading	---	---	3.53	---	15
CL-2	Condensate Truck Loading	---	---	3.53	---	15
EFL-1	Enclosed Flare	0.66	1.91	1.15	<0.01	946
WL-1	Produced Water Truck Loading	---	---	0.01	---	<1
WL-2	Produced Water Truck Loading	---	---	0.01	---	<1
AMINE-1	Amine Unit	---	---	7.39	---	8,116
AMINE-2	Amine Unit	---	---	7.39	---	8,116
FLARE2	Emergency Flare	0.88	4.39	0.04	<0.01	1,686
FLARE3	Emergency Flare	0.88	4.39	0.04	<0.01	1,686
FUG	Fugitive Sources	---	---	6.93	---	329
FUG2	Fugitive Sources	---	---	6.85	---	318
BD	Engine Blowdowns	---	---	16.62	---	2,295
BD2	Turbine Blowdowns	---	---	4.60	---	635

Startup, shutdown, and maintenance (SSM) activities for the new equipment items are included in this review. Based on operational parameters no SSM BACT was needed for any of the affected emission units. The emission limits established in the permit apply to the units during SSM as well as during the normal operation of those units. Therefore, there is no need for secondary BACT limits or limitations on the number of SSM events. The new units are expected to comply with BACT limits when averaged over the appropriate time period (e.g., one hour for turbine NO_X limits, over three hours for engine CO limits, etc.).

1. <u>Top Down Process</u>

BACT results in a specific emission limitation based on the maximum degree of reduction for each pollutant and emission unit, on a case-by-case basis, taking into account technical feasibility, energy, environmental, and economic impacts. The case-by-case BACT determination results from an analysis referred to as a "top down" analysis.

The "top down" analysis required for BACT involves the identification of all applicable control technologies in order of effectiveness. The review is then conducted beginning with the "top", or most effective emission control and/or reduction technology to determine if the technology is technologically, environmentally, and economically feasible. If the analysis reveals that a technology is not feasible based on any of these criteria, the next most effective control technology is then evaluated in the same manner. This is continued until the control technology under consideration cannot be eliminated based on technological feasibility, environmental impacts, or economics. This control technology is then proposed as BACT.

The top down BACT approach must not only look at the most stringent emission limits previously approved, but it also must evaluate all demonstrated and potentially applicable technologies, including innovative controls, lower polluting processes, etc. These technologies and emission limits are generally identified through a review of the EPA RACT/BACT/LAER Clearinghouse (RBLC). If the proposed BACT is equivalent to the most stringent emission limit (top), no further analysis is necessary. However, if the most stringent emission limit is not selected, additional analyses are required. Any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic" impacts, as described previously.

The determination of what constitutes BACT is left to the ODEQ, and allows that agency to consider the weight or emphasis to be placed on the energy, environmental, and economic impacts of control. This allows the state agency to consider, on a case-by-case basis, the size of the facility, the increment of air quality which will be absorbed by any particular major-emitting facility, anticipated and desired economic growth for the area, and other concerns that may impact the agency's decision-making process. In no event can the application of BACT be less stringent than any applicable NSPS or NESHAP standard. BACT should be established as a numerical emission limit or standard in the permit.

The five basic steps involved in the "top down" BACT analysis are listed below:

- Step 1. Identify Available Control Technologies
- Step 2. Eliminate Technically Infeasible Options
- Step 3. Rank Remaining Control Technologies by Control Effectiveness
- Step 4. Evaluate Most Effective Controls Based on Energy, Environmental, and Economic Impacts
- Step 5. Select BACT and Document the Selection as BACT

If due to technological or economic limitations to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

2. Green House Gases (GHG)

For the purpose of the BACT analysis, GHG is assumed to be composed primarily of CO_2, with much smaller quantities of CH_4 and N_2O. Under EPA's new guidelines for GHG BACT, the typical top-down analysis approach is to be followed. Since CO_2 is not typically feasible to control, the applicant evaluated using electric motors to drive compressors and efficient combustion using natural gas, rather than end-of-stack types of control systems.

The use of electric motors (rather than natural gas-fired reciprocating engines and turbines) to drive compressors at the facility was rejected based on reliability and cost considerations. In addition, most of the electricity generated in the state of Oklahoma is derived from the combustion of fossil fuels. Factoring in electric line losses, the combustion of natural gas at the facility is expected to show lower GHG emissions than using electricity derived from the combustion of fossil fuels at a distant point of generation.

One end-of-stack control option to be considered is geologic sequestration of GHG. However, sequestration is not yet commercially available and appropriate geologic formations have not been proven for long-term underground storage in the vicinity of the facility. In addition, collateral environmental impacts that could result from sequestration have not been evaluated and require further study. Therefore, geologic sequestration is not considered to be a technically feasible control option at this time and is therefore eliminated from further consideration in this analysis. In addition, since sequestration is not yet commercially available, it is not possible to accurately estimate control costs. Use of alternative fuels, or fuel switching, is not a control option that would typically be considered in the top-down CO_{2e} BACT analysis. However, for this project this issue is moot, because combustion of natural gas produces less GHG emissions per unit of energy than other fossil fuels. For CO_{2e}, the resulting BACT for all proposed equipment other than the RICE and turbines is efficiency and good work practices.

3. Engines

The facility is proposing to install twelve natural gas fired spark ignition (SI) reciprocating internal combustion engines (RICE) at the Rose Valley Plant. Ten of the proposed RICE will be Caterpillar G3606LE compressor engines rated at 1,775 hp. The other two will be backup engines (used to power generators); the backup engines will be Caterpillar G3520C IM engines rated at 2,889 hp. Both models are four-stroke lean-burn (4SLB). The BACT analysis for the engines is for NO_X, CO, VOC, $PM_{2.5}$, and CO_{2e}. The proposed engines will be subject to 40 CFR Part 60, NSPS, Subpart JJJJ and 40 CFR Part 63, NESHAP, Subpart ZZZZ. The standards for natural gas fired engines with a maximum horsepower rating greater than or equal to 500-hp which are manufactured after July 1, 2010, are 1.0 g/hp-hr NO_X, 2.0 g/hp-hr CO, and 0.7 g/hp-hr for VOC.

Step 1 - Identify Available Control Technologies

A review of previous BACT analyses was conducted to identify available control technologies for consideration. The search was conducted for 4SLB SI RICE ≥ 500-hp. The applicant queried the database for determinations between January 2005 and July 2010 for engines operating under SIC Codes 1311 and 1321. The AQD review included all SIC Codes for similar operations through September of 2012. The technologies identified for evaluation are summarized below.

Control Technologies Identified for BACT Analysis

Pollutant	Control Technologies Identified
CO	Oxidation Catalyst
	Good Combustion Practices
VOC	Oxidation Catalyst
	Good Combustion Practices
NO_X	Selective Non-Catalytic Reduction (SNCR)
	Selective Catalytic Reduction (SCR)
	Lean-Burn Combustion (LBC)
$PM_{2.5}$	Combustion of Natural Gas / Good Combustion Practices

According to RBLC, the proposed lean-burn engines have the lowest emissions of CO and VOC in comparison with other engines operating under SIC Codes 1311 and 1321. The search results for CO are summarized below.

RBLC Search Results for CO

RBLC ID	SIC Code	Emission Rate (g/hp-hr)	RBLC ID	SIC Code	Emission Rate (g/hp-hr)
IA-0077	4922	0.2	WV-0020	4922	2.1
CO-0058	4922	0.2	IL-0083	4922	2.2
GA-0141	4922	0.2	WY-0066	1311	2.4
TX-0364	1321	1.2	TX-0408	2819	3.0
TX-0364	1321	1.2	LA-0141	1321	3.0
TX-0364	1321	2.0	TX-0364	1321	4.8
TX-0501	1321	2.0			

The proposed BACT emission limit for CO (0.36 g/hp•hr for the Caterpillar G3606LE engines and 0.43 g/hp•hr for the Caterpillar G3520C IM engines) is similar to the levels indicated and the control (oxidation catalyst) is equivalent to the types of controls installed on the engines listed. The three lowest emissions limits are based on installation of an oxidation catalyst and 93% control of CO emissions in accordance with 40 CFR Part 63, Subpart ZZZZ (MACT). However, the NO_X emission limits for these engines were permitted at a higher emission level (~1.0 g/hp-hr) resulting in reduced CO emissions. The engines proposed for installation at this facility are manufactured and set for the lowest possible NO_X setting (0.50 g/hp•hr) which increases the CO emissions. The proposed BACT is also due to the type of catalyst and the catalyst manufacturer's guarantee of 87% control efficiency for the Caterpillar G3608LE engines and 80% for the Caterpillar G3520C IM engines. BACT for CO is selected as use of oxidation catalyst systems with a maximum CO emission rate of 0.36 g/hp•hr for the Caterpillar G3606 LE engines and 0.43 g/hp•hr for the Caterpillar G3520C IM engines.

The search results for VOC are summarized below.

RBLC Search Results for VOC

RBLC ID	SIC Code	Emission Rate (g/hp-hr)	RBLC ID	SIC Code	Emission Rate (g/hp-hr)
LA-0232	4922	0.2	IA-0077	4922	0.7
TX-0364	1321	0.3	WV-0020	4922	0.7
CO-0058	4922	0.3	WY-0066	1311	0.9
GA-0104	4922	0.3	TX-0364	1321	1.2
IL-0083	4922	0.4	TX-0408	2819	1.2
LA-0141	1321	0.5	TX-0501	1321	1.4
TX-0364	1321	0.6	TX-0364	1321	1.6

The proposed BACT emission limit for VOC (0.13 g/hp•hr for the Caterpillar G3606LE engines and 0.44 g/hp•hr for the Caterpillar G3520C IM engines) is equivalent (or nearly equivalent) to the listed levels and type of control (oxidation catalyst) so no further analysis was conducted since it is the most stringent control. BACT for VOC is selected as use of oxidation catalyst systems with a maximum VOC emission rate of 0.13 g/hp•hr for the Caterpillar G3606 LE engines and 0.44 g/hp•hr for the Caterpillar G3520C IM engines.

The proposed BACT for $PM_{2.5}$ is the burning of natural gas and good combustion with emissions based on AP-42 (8/2000), Section 3.2 for 4-cycle lean burn engines (0.01 lb/MMBTU). There were no BACT determinations for $PM_{2.5}$ on the RBLC. There were some BACT determinations for PM_{10} which are listed below. However, for each of the determinations no controls were proposed. Therefore, no further analysis was conducted. BACT for $PM_{2.5}$ is selected as combustion of natural gas and good combustion practices with a maximum $PM_{2.5}$ emission rate of 0.01 lb/MMBTU for the Caterpillar G3606 LE engines and for the Caterpillar G3520C IM engines.

RBLC Search Results for PM_{10}

RBLC ID	SIC Code	Emission Rate (lb/MMBTU)
IA-0077	4922	0.01
WV-0020	4922	0.04
TX-0364	1321	0.01
TX-0364	1321	0.03
TX-0364	1321	0.05
TX-0408	2819	0.02

Additional information on control technologies for lean-burn engines was found in the EPA Report, “Stationary Reciprocating Internal Combustion Engines, Updated Information on NO_X

Emissions and Control Techniques, Revised Final Report" (2000). The NO_X control technologies identified for the engines are presented below.

Possible NO_X Control Technologies for Engines

Pollutant	Control Technology
NO_X	Selective Non-Catalytic Reduction (SNCR)
	Selective Catalytic Reduction (SCR)
	Lean-Burn Combustion (LBC)

Step 2 - Eliminate Technically Infeasible Options (NO_X)
Analysis of control technologies indicated that SNCR is not technically feasible for NO_X control. The use of SNCR requires injecting ammonia or urea into areas of the exhaust gas with temperatures in the range of approximately 1600 ºF to 2100 ºF to achieve proper NO_X reduction. If the exhaust gas is not at the correct operating temperature, SNCR requires additional fuel to heat the exhaust gas. In addition, SNCR can result in un-reacted ammonia or ammonia slip when temperatures are not in the optimum reaction range or when excess ammonia is injected into the exhaust gas. Typically, lower temperatures will cause an increase in the production of ammonia slip. The proposed engines for the facility will have exhaust gas temperatures of approximately 847 ºF to 870 ºF, depending on load capacity. This temperature range is well outside the optimum operating range for SNCR which would result in the production of ammonia slip and the inefficient reduction of NO_X emissions. This technology is not technically feasible for these engines; therefore, SNCR has been eliminated from BACT consideration and will not be discussed further.

Like the SNCR system, SCR requires injecting an ammonia or urea solution into the exhaust gas; however, SCR allows the reaction to occur at lower temperatures due to the introduction of a catalyst bed. The ammonia or urea injection system can again result in the production of un-reacted ammonia or ammonia slip. In order to ensure that correct amount of ammonia or urea is injected into the system, SCR typically includes monitoring systems upstream and/or downstream of the catalyst bed to function as a feedback system.

Many current systems utilize urea for the reagent as opposed to ammonia solutions. In urea systems, the first stage of the catalyst bed is the hydrolysis catalyst, which converts the urea to ammonia. The second stage of the catalyst allows ammonia and NO_X to react and forms nitrogen gas and water. As a secondary reaction, hydrocarbons react with oxygen to form water, carbon dioxide, and carbon monoxide. The third stage of the catalyst bed includes an oxidation catalyst where un-reacted ammonia oxidizes to form nitrogen gas and water.

The applicant offered an analysis of competing control technologies and the applicant made the case that SCR is not technically feasible for NO_X control. The applicant identified three general areas where problems with the SCR technology would warrant its rejection: (1) problems with load following and ammonia slip, (2) difficulty operating and maintaining the systems (resulting in SCR not being selected as BACT for a number of years), and (3) requirements for constant monitoring and impractical expansions of operator training. Despite making the case that the use of SCR is not technically feasible, the applicant offered an economic analysis of SCR control (discussed later). AQD rejects the applicant's argument that SCR is technically infeasible (while accepting the applicant's argument on cost-effectiveness, also discussed later). The reasons AQD rejects the applicant's analysis on the technical infeasibility of SCR are as follows: the load-following difficulties identified by the applicant may have been a problem 10 years ago, but that it not currently the case. In fact, urea-injection SCR systems are currently being installed on a large number of on-highway diesel engines to ensure compliance with 2010 emission limits. Those installations are found on heavy-duty trucks as well as school buses. Those applications demonstrate a high degree of load variability and the performance of those SCR systems has been robust.

Step 3 - Rank Control Technologies by Control Effectiveness (NO_X)
The next step is to rank control technologies not eliminated due to technical infeasibility in order of decreasing effectiveness.

Ranking of Control Technologies by Effectiveness

Pollutant	Control Technology	Control Level
NO_X	Selective Catalytic Reduction (SCR)	0.05 g/hp-hr
	Ultra Lean-Burn Combustion (ULBC)	0.50 g/hp-hr
	Lean-Burn Combustion (LBC)	0.70 g/hp-hr

Step 4 - Evaluate Most Effective Controls Based on Impacts (NO_X)
The highest NO_X reductions could be achieved using SCR technology. Therefore, the economic feasibility of this control option was evaluated. The result was that the reduction in NO_X emissions using SCR is not economically feasible based on overall cost estimates and incremental reduction of emissions from the proposed emission limit (0.5 g/hp-hr) as shown below.

The cost for the initial purchase and installation of the SCR and ammonia or urea reagent for the SCR is approximately $194,081 for the Caterpillar G3606LE and $195,161 for the Caterpillar G3520C. This cost includes the purchase of an oxidation catalyst which must be installed after the SCR to control the production of ammonia slip. Ammonia or urea must be continually purchased for use in the injection system. The cost of urea is approximately $35,000 per year depending on the current market price for urea at the time of purchase. The SCR catalyst and other process elements must be cleaned after 5 years of use. In addition, the oxidation catalyst requires additional maintenance and cleaning costs. A comparison table of the cost estimates for additional reductions from a SCR added to a ULBC engine and a ULBC are presented below.

SCR VS ULBC Cost Comparison for CAT G3606LE and CAT G3520C IM Engines

Factor	SCR G3606LE	SCR G3520C	ULBC
Total Capital Investment	$194,081	$231,233	$ 0
Total Direct Annual Cost	$62,342	$62,342	$ 0
Total Indirect Annual Cost	$35,396	$41,170	$ 0
Total Annualized Cost	$97,738	$104,512	$ 0
Design Control Efficiency	90%	90%	75%
Tons NO_X Removed per Year	7.7	12.56	25.71
Cost Effectiveness per Ton of NO_X Removed	$12,672	$8,325	N/A

It should be noted that the Caterpillar G3520C IM engines will be limited to 750 hours of operation per year and the cost effectiveness with that limitation will be impacted to an even greater degree.

Step 5 - Select BACT and Document the Selection as BACT (NO_X)

The additional cost of the SCR system is too high and is not warranted or justified for the engines at this facility based on the relatively low additional reduction in NO_X emissions. Due to the economic infeasibility of SCR, the technology has been eliminated as BACT for the proposed engines at this facility. Natural gas-fired lean-burn SI engines without add-on controls for NO_X can meet or exceed a NO_X emission limit that is equivalent to the NSPS Subpart JJJJ requirements for SI ICE of 1.0. The lean-burn combustion technology is a low emission technology and is already integrated into the proposed engines as purchased. Thus, this technology does not result in any additional costs beyond the cost of the initial purchase and the normal operation and maintenance of the engine. BACT for NO_X is selected as no add-on controls for the lean-burn engines with a NO_X emissions rate limit of 0.5 g/hp•hr.

Additional Review for Greenhouse Gases (CO_{2e})

Because geologic sequestration has been eliminated as a control option due to technical infeasibility, and because these engines already burn natural gas, the only remaining control option to consider is efficiency. Based on the mechanical drive portion of the engines, the nominal efficiency of the engines is estimated at 37.4% for the Caterpillar G3606 LE engines and 36.8% for the Caterpillar G3520C IM engines. BACT for CO_{2e} for these units is natural gas combustion and good design and combustion practices.

Summary of Selected BACT for Engines

Pollutant	Control Technology	Emission Limits for the G3606 LE Engines	Emission Limits for the G3520C IM Engines
NO_X	Lean-Burn Combustion	0.50 g/hp-hr	0.50 g/hp-hr
CO	Oxidation Catalyst	0.36 g/hp-hr	0.43 g/hp-hr
VOC	Oxidation Catalyst	0.13 g/hp-hr	0.44 g/hp-hr
$PM_{2.5}$	Natural Gas Combustion	0.01 lb/MMBTU[1]	0.01 lb/MMBTU[1]
CO_{2e}	Efficient Design & Combustion	≤ 8,452 BTU/bhp-hr[2, 3]	≤ 8,212 BTU/bhp-hr[2, 3]

[1] - Based on AP-42 (4/2000), Section 3.2.
[2] - Based on loads ≥ 50%.
[3] - Based on HHV

4. Turbines

The applicant is proposing to install two 9,443-hp Siemens SGT-200-2S natural gas-fired turbines at the Rose Valley Plant. The BACT analysis for the turbines is for NO_X, CO, VOC, $PM_{2.5}$, and CO_{2e}. The proposed turbines will be subject to 40 CFR Part 60, NSPS, Subpart KKKK. The standards for natural gas-fired turbines with a maximum heat input greater than 50 MMBTUH and less than or equal to 850 MMBTUH which commence construction after February 18, 2005, is 25 ppmdv NO_X @ 15% O_2.

Step 1 - Identify Available Control Technologies
A review of previous BACT analyses was conducted to identify available control technologies for consideration. The search was conducted for turbines similar to the units being proposed. The database was queried for small (<25 MW) simple cycle turbines permitted from January 2005 to July 2010 for turbines operating under the same SIC Codes. The AQD review included all SIC Codes for similar operations through September of 2012. The technologies identified for evaluation are summarized below.

Control Technologies Identified for BACT Analysis

Pollutant	Control Technologies Identified
VOC	Oxidation Catalyst
	Good Combustion Practices
CO	Good Combustion Practices
NO_X	Selective Catalytic Reduction (SCR)
	Ultra Dry-Low NO_X Combustion (UDLN)
	Dry-Low NO_X Combustion (DLN)
$PM_{2.5}$	Combustion of Natural Gas / Good Combustion Practices

According to RBLC, the proposed turbines have the lowest emissions of NO_X, CO, and VOC in comparison with other turbines operating under SIC Code 1311 and 1321.

The proposed BACT for $PM_{2.5}$ is the burning of natural gas and good combustion with emissions based on AP-42 (4/2000), Section 3.1 for turbines (0.0066 lb/MMBTU). There were no BACT determinations for $PM_{2.5}$ on the RBLC. There were some BACT determinations for PM_{10} which were also based on the AP-42 emissions factor. Therefore, no further analysis was conducted.

The proposed BACT emission limit for VOC (10 ppmv UHC @ 15% O_2) is below the listed levels and type of control (no control). The AP-42 (4/2000), Section 3.1 factor for VOC from natural gas fired turbines is 0.0021 lb/MMBTU.

RBLC BACT Search Results for VOC

RBLC ID	SIC Code	Emission Rate (lb/MMBTU)	Emission Rate (ppmdv)	RBLC ID	SIC Code	Emission Rate (lb/MMBTU)	Emission Rate (ppmdv)
NV-0050	7011	0.024	17[1]	FL-0266	4911	0.0138[1, 2]	10[1]
WY-0067	1321	0.035[1]	25	CO-0059	4922	0.0041[1]	3
WY-0067	1321	0.069[1]	50	CO-0058	4922	0.0041[1]	3
AL-0251	4911	0.0068	5[1]	TX-0454	4922	0.0036[1]	3[1]
LA-0232	4922	0.033	25[1]	TX-0468	2869	0.0139[1]	10[1]
NV-0048	4925	0.0069	5[1]	NJ-0055	4922	0.0031	2[1]
MD-0035	4925	0.004[2]	3[1]	ID-0011		0.0031	2[1]
MD-0036	4911	0.003[2]	2[1]				

[1] – Estimated; [2] – Use of Oxidation Catalyst

The proposed BACT emission limit for CO (15 ppmv @ 15% O_2) is similar to the levels indicated and the control (no control) is equivalent to the types of controls installed on the turbines listed. The lowest emissions limit was based on installation of the Lowest Achievable Emission Rate (LAER) for the applicable non-attainment area and required installation of an oxidation catalyst.

RBLC BACT Search Results for CO

RBLC ID	SIC Code	Emission Rate (ppmdv)	RBLC ID	SIC Code	Emission Rate (ppmdv)
NV-0048	4922	16.0 @ 15% O_2	AR-0075	2421	50.0 @ 15% O_2
CO-0058	4922	24.5 @ 15% O_2	WY-0059	4922	50.0 @ 15% O_2
CO-0059	4922	25.0 @ 15% O_2	AK-0062	1311	50.0 @ 15% O_2

The proposed BACT emission limit for NO_X (15 ppmv @ 15% O_2) is similar to the levels indicated and the control (low-NO_X combustion) is equivalent to the types of controls installed on the turbines listed.

RBLC BACT Search Results for NO_X

RBLC ID	SIC Code	Emission Rate (ppmdv)	RBLC ID	SIC Code	Emission Rate (ppmdv)
NV-0050	7011	5.0 @ 15% O_2	WA-0297	4924	25.0 @ 15% O_2
AR-0075	2421	14.0 @ 15% O_2	WA-0297	4924	25.0 @ 15% O_2
LA-0232	4922	15.0 @ 15% O_2	NV-0048	4922	25.0 @ 15% O_2
CO-0059	4922	15.0 @ 15% O_2	WA-0316	4923	25.0 @ 15% O_2
LA-0232	4922	15.0 @ 15% O_2	WY-0059	4922	25.0 @ 15% O_2
FL-0266	4911	20.0 @ 15% O_2	CO-0058	4922	48.0 @ 15% O_2
WA-0316	4923	25.0 @ 15% O_2	AK-0062	1311	85.0 @ 15% O_2

Step 2 - Eliminate Technically Infeasible Options
None of the control technologies were eliminated as technically infeasible.

Step 3 - Rank Control Technologies by Control Effectiveness (NO_X, CO & VOC)
The next step is to rank control technologies not eliminated due to technical infeasibility in order of decreasing effectiveness.

Ranking of Control Technologies by Effectiveness

Pollutant	Control Technology	Control Level
NO_X	Selective Catalytic Reduction (SCR)	2.5 ppmdv @ 15% O_2
	Ultra Dry-Low NO_X Combustion (UDLN)	5.0 ppmdv @ 15% O_2
	Dry-Low NO_X Combustion (DLN)	15.0 ppmdv @ 15% O_2
CO	Oxidation Catalyst	2.5 ppmdv @ 15% O_2
	Dry-Low NO_X Combustion (DLN)	15.0 ppmdv @ 15% O_2
VOC	Oxidation Catalyst	2.5 ppmdv @ 15% O_2
	Dry-Low NO_X Combustion (DLN)	10.0 ppmdv @ 15% O_2

Step 4 - Evaluate Most Effective Controls Based on Impacts (NO_X, CO & VOC)
The economic feasibility of SCR was evaluated. The result was that the reduction in NO_X emissions using SCR is not economically feasible based on overall cost estimates and incremental reduction of emissions from the proposed emission limit (15 ppmdv @ 15% O_2) as shown below.

The annualized cost for NOx reductions using an SCR system on a similarly-sized turbine is approximately $20,000 per ton. The annualized cost for CO and VOC reductions on a similarly-sized turbine is approximately $6,000 per ton of CO removed and approximately $25,000 per ton of VOC removed.

Step 5 - Select BACT and Document the Selection as BACT (NO_X, CO & VOC)
The additional cost of the SCR system is too high and is not warranted or justified for the turbines at this facility based on the relatively low additional reduction in NO_X emissions. Due to economic infeasibility of SCR, the technology has been eliminated as BACT for the proposed turbines at this facility. Natural gas-fired DLN turbines without add-on controls for NO_X can

meet or fall below a NO_X emission limit that is equivalent to the NSPS, Subpart KKKK requirements of 25 ppmdv @ 15% O_2. The DLN combustion technology is a low emission technology and is already integrated into the proposed turbines as purchased. Thus, this technology does not result in any additional costs beyond the cost of the initial purchase and the normal operation and maintenance of the turbine. BACT for NO_X emissions is selected as no add-on controls for the turbines at a maximum NO_X concentration of 15 ppmdv @ 15% O_2.

The additional cost of an oxidation catalyst is too high and is not warranted or justified for the turbines at this facility. Due to economic infeasibility of an oxidation catalyst, the technology has been eliminated as BACT for the proposed turbines at this facility. BACT for CO and VOC emissions is selected as no add-on controls for the turbines with a maximum concentration of 15 ppmdv CO @ 15% O_2 and 10 ppmdv VOC @ 15% O_2. BACT for $PM_{2.5}$ is selected as the burning of natural gas with an emission rate of 0.0066 lb/MMBTU.

<u>Additional Review for Greenhouse Gases</u>
Because geologic sequestration has been eliminated as a control option due to technical infeasibility, and because these turbines already burn natural gas, the only remaining control option to consider is efficiency. Based on the mechanical drive portion of the turbines, the efficiency of the turbines is estimated at 33%. BACT for CO_{2e} is selected as efficient natural gas combustion at a fuel consumption rate less than or equal to 8,298 BTU/bhp•hr.

The selected BACT for the two 9,443-hp Siemens SGT-200-2S turbines is summarized in a table below.

Summary of Selected BACT for Turbines

Pollutant	Control Technology	Emission Limits
NO_X	Dry-Low NO_X Combustion	15 ppmdv @ 15% O_2
CO	Efficient Design & Combustion	15 ppmdv @ 15% O_2
VOC	Efficient Design & Combustion	10 ppmdv @ 15% O_2
$PM_{2.5}$	Natural Gas Combustion	6.6E-03 lb/MMBTU[1]
CO_{2e}	Efficient Design & Combustion	≤ 8,298 BTU/bhp-hr[2, 3]

[1] - Based on AP-42 (4/2000), Section 3.1.
[2] - Based on loads ≥ 75%.
[3] - Based on LHV

5. <u>Heaters</u>

The applicant is proposing to install four new heaters: two 5.605 MMBTUH regeneration heaters and two 17.4-MMBTUH hot oil heaters at the facility. The BACT analysis for the heater is for NO_X, CO, VOC, $PM_{2.5}$, and CO_{2e}. The two 17.4-MMBTUH heaters will be subject to 40 CFR Part 60, NSPS, Subpart Dc. Since the proposed heaters will burn natural gas as fuel, they will not be subject to any emission standards under this subpart.

Step 1 - Identify Available Control Technologies

A review of previous BACT analyses was conducted to identify available control technologies for consideration. The search was conducted for heaters similar to the unit being proposed. The applicant queried the database for commercial/institutional-size (<100 MMBTUH) boilers/furnaces permitted from January 2005 to July 2010 operating under the same SIC Code. AQD review included all SIC Codes for similar operations but limited to the same size range as the applicable heater. In addition, the AQD review extended the search through September of 2012. The technologies identified for evaluation are summarized below.

Control Technologies Identified for BACT Analysis

Pollutant	Control Technologies Identified
CO	Good Combustion Practices
VOC	Good Combustion Practices
NO_X	Low-NO_X Burners
	Good Combustion Practices
$PM_{2.5}$	Combustion of Natural Gas / Good Combustion Practices

According to RBLC, the proposed heaters have the lowest emissions of NO_X and CO in comparison with other heaters operating under SIC Codes 1311 and 1321. The search results for NO_X and CO emissions for heaters/boiler rated at ~10 MMBTUH are summarized below.

RBLC Search Results for NO_X, CO, and VOC

RBLC ID	SIC Code	Process	Emission Rate (lb/MMBTU)		
			NO_X	CO	VOC
TX-0364	1321	32.5-MMBTUH Hot oil heater	0.0600	0.0990	0.0065
TX-0364	1321	12.0-MMBTUH Hot oil heater	0.1180	0.0992	0.0067
TX-0364	1321	2.5-MMBTUH Glycol reboiler	0.1160	0.1000	0.0080
TX-0364	1321	3.0-MMBTUH TEG firebox	0.0967	0.0833	0.0067
AK-0062	1311	1.34-MMBTUH TEG reboiler	0.0800	0.1500	---
AK-0062	1311	34.0-MMBTUH Production heater	0.0950	0.1000	---
AK-0062	1311	14.9-MMBTUH Miscible injection heater	---	0.1200	---
WY-0066	1311	21.0-MMBTUH Gasification preheater	0.0500	0.0800	---
TX-0501	1321	93.0-MMBTUH Power steam boiler	0.0902	0.0758	0.0048
WY-0067	1321	84.0-MMBTUH Hot oil heater	0.0300	0.0200	0.0200
WY-0067	1321	72.0-MMBTUH Amine unit heater	---	---	0.0400
WA-0316	4923	4.2-MMBTUH Boiler	0.0400	---	---
NV-0046	4922	3.9-MMBTUH Boiler	0.1010	0.0830	0.0052
NV-0048	4922	3.9-MMBTUH Boiler	0.1000	0.0830	0.0050
MD-0035	4925	88.4-MMBTUH Vaporization heater [1]	0.0120	0.0300	0.0020
MD-0035	4925	1.3-MMBTUH Emergency vent heater	0.0360	---	0.0054
CO-0058	4922	45.0-MMBTUH Heater	0.0350	0.0370	0.0160

[1] Equipped with ultra low-NO_X burners and oxidation catalyst.

The proposed BACT for CO_{2e}, VOC, and $PM_{2.5}$ is the burning of natural gas and good combustion with emissions based on AP-42 (7/1998), Section 1.4 for heaters. There were some BACT determinations for VOC and PM_{10} but they were based on the AP-42 emissions factors. VOC emissions rates are included in the table, but no further analysis was conducted for these pollutants. BACT for VOC is selected as good combustion practices with an emission rate limit of 0.0054 lb/MMBTU.

The proposed BACT emission limit for NO_X (0.045 lb/MMBTU) is equivalent to the listed levels and type of control (LNB) and no further analysis was conducted. Some of the lower emission limits include flue gas recirculation and ultra LNB. However, for the heaters of the size proposed for this project, the proposed emission limit is acceptable as BACT. BACT for NO_X is selected as low-NO_X burners with an emission rate limit of 0.045 lb/MMBTU.

The proposed BACT emission limit for CO (0.0824 lb/MMBTU) is similar to the levels indicated and the control (no control) is equivalent to the types of controls installed on the heaters listed and no further analysis was conducted. BACT for CO is selected as good combustion practices with an emission rate limit of 0.0824 lb/MMBTU.

<u>Considerations for GHG</u>
Because geologic sequestration has been eliminated as a control option due to technical infeasibility, and because this emission unit already burns natural gas, the only remaining control option to consider is efficiency. The heaters proposed for this project are designed for 80% efficiency. BACT for these units is selected as natural gas combustion and good design and combustion practices with a maximum CO_{2e} emission rate of 118 lb/MMBTU. No further analysis was conducted for GHG.

Step 5 - Select BACT and Document the Selection as BACT (NO_X, CO & VOC)

The proposed BACT is summarized below and no further analysis was conducted.

Summary of Selected BACT for Heaters

Pollutant	Control Technology	Emission Limits
NO_X	Low NO_X Burners	0.045 lb/MMBTU
CO	Good Combustion Practices	0.0824 lb/MMBTU [1]
VOC	Good Combustion Practices	0.0054 lb/MMBTU [1]
PM	Natural Gas Combustion	0.0075 lb/MMBTU [1]
CO_{2e}	Natural Gas Combustion	118 lb/MMBTU [1]

[1] Based on AP-42 (7/1998), Section 1.4.

6. <u>Amine Units</u>

The applicant is proposing to install two 20,000-bbl/day amine units at the facility. Each amine unit is estimated to release 7.49 TPY VOCs and 8,116 TPY CO_{2e}.

Step 1 – Identify Available Control Technologies
The first step in the BACT analysis is to identify available control technologies for each pollutant. A review of the EPA RACT, BACT, and LAER Clearinghouse (RBLC) was conducted to identify available control technologies for these types of emission sources. One amine unit was found at a facility with SIC 1321 and one amine unit was found at a facility with SIC 2911, shown in the table below.

RBLC ID	SIC Code	Control Technology
WY-0067	1321	Thermal Oxidizer
TX-0492	2911	No Add-On Controls

There are two types of emissions associated with each amine unit: gases emitted from the flash tank and exhaust from the still vent. The applicant evaluated two possible control technologies for each type of emission for each amine units: (1) use of a flare/thermal oxidizer and (2) routing the emissions to the hot oil heater.

Step 2 – Eliminate Technically Infeasible Options

Combustion of still vent and flash tank emissions from the amine units by flare or thermal oxidizer can provide up to 98% control of the VOC from both streams. Routing the flash tank emissions to be used to fuel the hot oil heater can provide 95% control of the flash emissions. Neither option has been eliminated due to technical infeasibility.

Step 3 – Rank Control Technologies by Control Effectiveness

The next step is to rank control technologies not eliminated due to technical infeasibility in order of decreasing effectiveness. The table below presents the technologies and their approximate control levels.

Ranking of Control Technologies by Effectiveness

Control Technology	Approximate Controlled VOC Emission Level	Approximate Control Efficiency
Route Flash Gas to Flare/Thermal Oxidizer	0.16 lb/hr	98%
Route Flash Gas to the Hot Oil Heater	0.41 lb/hr	95%
Route Still Vent Emissions to Flare/Thermal Oxidizer	0.03 lb/hr	98%
Exhaust Still Vent Emissions to Atmosphere	1.28 lb/hr	0%

The option of routing the still vent emissions to the hot oil heater was not evaluated due to the low Btu content of the still vent emissions. This evaluation is presented in more detail in the discussion of Step 4.

Step 4 – Evaluate Most Effective Controls Based on Impacts

The highest VOC reductions could be achieved using a flare or thermal oxidizer. Therefore, the applicant evaluated the economic feasibility for additional analysis in the determination of BACT.

The gases emitted from the flash tank are in excess of 1,600 Btu/scf. With that Btu content, the flash gases are suitable for use in fueling the hot oil heater and may be combusted in a flare without supplemental fuel gas. In contrast, according to the Promax simulation for the amine systems, the still vent stream will be 435,803 scf/d at 10.03 Btu/scf. Flare systems typically need an average heat content of approximately 350 Btu/scf to maintain combustion. To increase the heating value to this level, approximately 255,000 scf/d of fuel gas will need to be mixed with the still vent stream. At a price of $3.00 per mscf, the annual fuel cost would be approximately $280,000. Construction cost increases to install the necessary piping and valves would be approximately $75,000.

The result is that the reduction in VOC emissions from the flash tank using a flare or thermal oxidizer over routing the flash stream to the hot oil heater is not economically feasible based on overall cost estimates for the controls; the table which follows provides a cost breakdown.

Amine Unit Flash Tank Emissions Control Cost Comparison

Factor	**Flare/Thermal Oxidizer**	**Route Flash Gas to Hot Oil Heater**
Total Capital Investment	$ 75,000	$0
Total Annual Cost	$21,872 [1]	$0
Design Control Efficiency	98%	95%
Tons VOC Removed per Year	33.66	32.63
Cost Effectiveness per Ton of VOC Removed	$ 1,063 [2]	N/A

[1] The annual cost represents the value of the gas that would need to be burned in the hot oil mixture in place of the flash gas stream.

[2] Cost effectiveness is in comparison to a “no control” option. Relative cost effectiveness (compared to routing the flash gas to the hot oil heater) would be $34,746.

The use of a flare/thermal oxidizer would only provide 1.03 TPY in additional VOC control over that provided by routing the flash gas to the hot oil heater. In addition to the costs shown, the use of a flare/thermal oxidizer would result in a lower effective energy efficiency, because additional fuel would need to be diverted to the hot oil heater to make up for the Btu content of the flash gas.

The following table shows the cost per ton of VOC removed if the still vent emissions are routed to a flare/thermal oxidizer with supplemental fuel. The analysis shows that this control option is not cost effective.

Amine Unit Still Vent Emissions Control Cost Comparison

Factor	**Flare/Thermal Oxidizer**
Total Capital Investment	$ 75,000
Total Annual Cost	$ 280,000
Design Control Efficiency	98%
Tons VOC Removed per Year	5.48
Cost Effectiveness per Ton of VOC Removed	$ 53,634

Step 5 – Select BACT and Document the Selection of BACT
Based on the cost analysis, the option of combusting the still vent stream for VOC control is not viable. BACT for VOC is selected as routing the flash gas to the hot oil heater at a maximum VOC emission rate of 0.41 lb/hr and exhausting the still vent emissions to the atmosphere at a maximum VOC emission rate of 1.28 lb/hr.

Selected BACT for the Amine Units

Pollutant	Control Technology	Controlled VOC Emission Level
VOC	Route Flash Gas to Hot Oil Heater	0.41 lb/hr
	Exhaust Still Vent Emissions to the Atmosphere	1.28 lb/hr

<u>Considerations for GHG</u>
The primary purpose of the amine treating process is to remove CO_2 and (if present) H_2S from the natural gas liquids produced at the plant. As such, emissions of CO_2 from this vent are unavoidable. Because geologic sequestration has been eliminated as a control option due to technical infeasibility, BACT for this pollutant is efficiency and good work practices with a maximum CO_{2e} emission rate of 8,116 ton/year.

7. <u>Condensate Tanks</u>
The applicant is proposing to install four new 1,000-bbl condensate storage tanks at the facility. The tanks will be subject to the requirements of NSPS, Subpart Kb. The applicant proposed to control VOC emissions from the tanks using a flare. The BACT analysis is for VOC.

Step 1 – Identify Available Control Technologies
A review of previous BACT analyses was conducted to identify available control technologies for consideration. The search was conducted for tanks similar to the units being proposed. The database was queried for tanks permitted from January 2002 to October 2012. No similar tanks were found that operate at a facility with SIC 1311 or 1321. One condensate tank was found at a facility with SIC 4922 as shown below.

RBLC ID	SIC Code	Control Technology
LA-0232	4922	Submerged Fill Pipe

The applicant identified two additional potential control technologies for evaluation.

Pollutant	Control Technology
VOC	Flare/Combustion
	Vapor Recovery

Step 2 – Eliminate Technically Infeasible Options
Combustion of tank vapors involves capturing emissions and burning them in a flare or combustion chamber. This option provides a capture efficiency estimated at 98% and a combustion destruction efficiency estimated to be 98%, yielding an overall control efficiency of 96.04%. Vapor recovery, or a vapor recovery unit (VRU), captures tank vapors, compresses them

with a small electric compressor and routes them back to the inlet suction. This option can provide 100% control efficiency (less fugitive losses) when the VRU is operational, but provides no control when the unit is not operational during malfunction or maintenance. For this reason, the applicant frequently permits VRUs with an allowance for 5% downtime, making the overall efficiency for the VRU approximately 95%. A submerged fill pipe reduces working emissions by preventing liquids from splashing, which causes more vapor generation. All VOC tanks with a capacity of 400 gallons or more are required by OAC 252:100-37-15(b) to be equipped with a permanent submerged fill pipe or a vapor recovery system, unless those tanks are subject to equipment standards (e.g., a fixed roof in combination with an internal floating cover, an external floating roof, or a closed vent system and control device) included in 40 CFR 60 Subparts K, Ka, or Kb. Tanks subject to those requirements are exempt from the requirements of 252:100-37-15(a) and (b).

Neither of the control technologies identified (flare/combustion or vapor recovery) can be eliminated as technically infeasible at the Rose Valley Plant and submerged fill alone will not satisfy the requirements of NSPS, Subpart Kb.

Step 3 – Rank Control Technologies by Control Effectiveness
The following table ranks the control technologies in order of effectiveness.

Pollutant	Control Technology	Approximate Control Efficiency
VOC	Flare/Combustion	96%
	Vapor Recovery	95%

Step 4 – Evaluate the Most Effective Controls Based on Impacts
The most effective control for the condensate tanks is flare/combustion.

Step 5 – Select BACT and Document the Selection as BACT
The applicant is proposing flare/combustion control as BACT for the condensate tanks, because this control method will provide the highest VOC control efficiency. BACT for VOC is selected as combustion of the vapor emissions in a controlled flare with a maximum emission rate of 0.41 TPY per process train and a maximum throughput of 4,599,000 gallons of condensate per year per process train.

Considerations for GHG
Vapor recovery would provide a greater reduction in CO_{2e} emissions, but would result in an increase in VOC emissions. In addition, the emergency flares are required for safety/operational considerations and those flares will experience CO_{2e} emissions regardless of whether or not they are used to control VOC emissions from the condensate storage tanks.

8. Emergency Flares
The facility is proposing to install two emergency flares at the facility. The flares will be used to control CH_4 and VOC emissions from various process units. The waste gases combusted in each emergency flare is estimated to be 2.66 MMBTUH (LHV). The BACT analysis for the flares is for NO_X, CO, VOC, $PM_{2.5}$, and CO_{2e}. The emergency flares are control devices for emissions of

CH_4 and VOC. The emissions of NO_X, CO, $PM_{2.5}$, and CO_{2e} are the result of combustion of the CH_4 and VOC. Sizing of the flare is an important aspect in the control of CH_4 and VOC. The flare is subject to NSPS, Subparts A and OOOO. As BACT for these flares, the AQD is proposing compliance with manufacturer operating and maintenance procedures and the requirements of 40 CFR Part 60, §60.18. By combusting the potentially released CH_4, operation of the flare will actually reduce the CO_{2e} emissions from venting of CH_4 from the facility by 20 times.

9. <u>Produced Water Storage Vessels</u>

The applicant is proposing to install four 400-barrel produced water storage vessels at the the facility. The BACT analysis for the produced water storage vessels is for VOC and CO_{2e}. BACT for VOC and CO_{2e} for the produced water storage vessels is selected as routing the emissions to an enclosed flare. Emission rates of both pollutants will be negligible.

10. <u>Condensate Truck Loading</u>

The facility is proposing to install a condensate truck loading station at the Rose Valley Plant. The BACT analysis for the condensate loading operations is for VOC. BACT for the condensate truck loading operations is to route the emissions to an enclosed flare with a maximum VOC emission rate of 3.53 TPY at a maximum condensate throughput of 4,599,000 gallons per year.

11. <u>Fugitive Equipment Leaks</u>

The facility will have fugitive equipment leaks related to operation of the Rose Valley Plant. The BACT analysis for the fugitive equipment leaks is for VOC and CO_{2e}. Compliance with leak detection and repair regulations, as specified in 40 CFR Part 60, Subpart OOOO, for VOC control, is selected as BACT for VOC and CO_{2e}.

12. <u>Blowdowns</u>

The facility will have blowdowns as part of the facility startup and shutdown procedures at the Rose Valley Plant. The BACT analysis for blowdowns is for VOC. Blowdowns on compressor units will occur on an “as needed” basis for maintenance and operational activities. When blowdowns are required, on-skid piping and valves will be manipulated to allow the entire unit to be equalized with the lowest available process pressure thereby reducing the total mass of the blowdown. Directing blowdowns into the flare was not considered due to the associated costs. Associated pipe and valve material as well as fabrication and installation would cost approximately $600,000 for a cost of approximately $28,000 per ton. BACT for this activity is no add on controls and limiting the permitted blowdowns to 5.85 MMSCF/yr for the engines and 1.62 MMSCF/yr for the turbines.

C. Ambient Air Impact Analysis

If a source has the potential to emit a pollutant above the PSD significance levels then they trigger an air quality impact evaluation. The evaluation includes atmospheric dispersion modeling for the following pollutants for which the PSD significance emission rates will be exceeded:

- Nitrogen Oxides, NO_X
- Carbon Monoxide, CO
- Particulate Matter, $PM_{2.5}$
- Ozone, O_3

If the maximum predicted concentrations due to the project emission increases (proposed construction) exceed the significant impact levels (SIL) a radius of impact is established and the facility has to conduct refined modeling to include nearby sources within 50 km of the radius of impact to verify compliance with the following air quality standards:

- National Ambient Air Quality Standards (NAAQS), and
- Class II Area PSD Increments, and
- Class I Area PSD Increments, for any Class I area within 300 km of the facility.

EPA regulates VOC and NO_X as precursors to tropospheric ozone formation. Ozone is unique because the EPA has not established a PSD modeling significance level (an ambient concentration expressed in either $\mu g/m^3$ or ppmv) for ozone. However, EPA has established an ambient monitoring *de minimis* level, which is different from other criteria pollutants, because it is based on a mass emission rate (100 TPY) instead of an ambient concentration (in units of $\mu g/m^3$ or ppmv). Ozone is reviewed in the Monitoring section.

This modeling analysis follows the Oklahoma Air Quality Division Modeling Section (AQD) guidance document "Air Dispersion Modeling Guidelines for Oklahoma Air Quality Permits", April 2011.

1. Model

The steady-state dispersion model, AERMOD (Version 12060), was used to predict all off property impacts from the facility. The AERMOD model was selected based on several factors. The selection factors include:

- acceptance by the EPA and many state agencies
- ability to handle flat, intermediate, and complex terrain
- ability to incorporate building downwash into the predicted concentrations
- ability to apply several different averaging periods, including annual.

2. Nearby Source Inventory

The NO_X, CO, and $PM_{2.5}$ nearby source parameters and potential emission rates out to 50 km were provided by the AQD and were incorporated into the NAAQS modeling analyses.

3. Dispersion Model Options

The AERMOD model was used in the modeling analysis and includes many options that can be selected by the user to adapt to many different modeling situations. The modeling options selected for this analysis are summarized on below.

i) Downwash Analysis

The EPA Building Profile Input Program (BPIP-Prime) was used to estimate the downwash effects of the compressor buildings. The latest BPIP-Prime program (version 04274) was used for these calculations.

The ten Caterpillar G3606LE engines will be located in separate buildings separated by only a few feet. Each of the compressor engine stacks, as well as each additional emission point, has a vertical unobstructed release.

ii) Land Use

Based on an evaluation of the United States Geologic Service (USGS) 1:24,000 scale maps for the area including the facility, the predominant land use is rural. Therefore, rural dispersion coefficients were used for all modeling.

iii) Receptor Grid

A series of nested receptor grids composed of several different spaced receptors was employed in the modeling analysis. After the plant boundary dimensions were determined, receptors were spaced outward as follows: 100 m out to 1 km, 250 m out to 2.5 km, 500 m out to 5 km, 750 m out to 7.5 km, and finally 1 km out to 10 km.

iv) Terrain Data

The following USGS 7.5 min DEM terrain data were included in the modeling analysis: Alabaster Caverns, Alva, Alva SE, Avard, Belva, Carmen, Cedardale, Cherokee North, Cherokee South, Cleo Springs, Dacoma, Dacoma SE, Dacoma SW, Edith, Fairvalley, Fairvalley NE, Fairvalley SE, Fairvalley SW, Fairview, Fairview SE, Freedom, Glass Mountains, Glass Mountains NE, Glass Mountains NW, Glass Mountains SW, Helena, Hopeton, Ingersoll, Lambert, Mooreland, Mooreland SE, Mooreland SW, Quinlan, Phroso, Tegarden, Tegarden SE, Togo, Waynoka East, Waynoka NW, Waynoka West.

v) Meteorological Data

Air dispersion modeling was conducted using 2006-2010 meteorological data processed by AERMET (Version 11059) to generate the surface (SCF) and profile (PFL) files for input into AERMOD. The meteorological data consists of 5-minute Oklahoma Mesonet data as on-site data with National Climatic Data Center (NCDC) Integrated Hourly Surface (ISH) data, and Forecast System Laboratories (FSL) upper air rawinsonde observation (RAOB) data. The Oklahoma Mesonet data was provided to the AQD courtesy of the Oklahoma Mesonet, a cooperative venture between Oklahoma State University (OSU) and the University of Oklahoma (OU) and supported by the taxpayers of Oklahoma.

For this specific modeling analysis, Oklahoma Mesonet data from Alva (ALV2-116) Mesonet site was combined with ISH data from the Alva (KAVK-53933) National Weather Station (NWS) for 2006, the Vance Air Force Base (KWDG-53986) NWS for 2007, and the Enid (KEND-13909) NWS for 2008, 2009, and 2010, and FSL data from the Norman station (OUN-3984).

4. Significant Impact Modeling Analysis Results

The results of the modeling impacts were compared to the applicable significant impact levels (SIL) to determine if cumulative modeling analysis was required for each pollutant averaging period.

Pollutant	Averaging Period	SIL µg/m³	Impacts[1] µg/m³	≥ SIL
CO	1-hour	2,000	102.82	NO
	8-hour	500	54.01	NO
$PM_{2.5}$	24-hour	1.2	2.93	YES
	Annual	0.3	0.4	YES
NO_2	1-hour	7.5	77.34	YES
	Annual	1.0	5.23	YES

[1] - Based on the Maximum Impact or Highest 1st High.

This project resulted in ambient impacts above the SIL for the $PM_{2.5}$ 24-hour, $PM_{2.5}$ Annual, NO_X 1-hour, and NO_X Annual standards. Therefore, the applicant performed refined modeling for these pollutants and averaging periods. The refined modeling included a review of the NAAQS and Increment modeling. The NAAQS modeling included background monitoring data.

5. Monitoring Data

i) Comparison of Impacts with Monitoring Significance Levels

Pollutant	Averaging Period	MSL µg/m³	Impacts[1] µg/m³	≥ MSL
$PM_{2.5}$	24-hour	4.0	2.93	NO
NO_2	Annual	14	5.23	NO

[1] - Based on the Maximum Impact or Highest 1st High.

Available monitoring data is acceptable because it is “within the time period that maximum pollutant concentrations would occur” and is complete and adequate enough to determine if the facility will cause or contribute to a violation of the NAAQS.

ii) Background Data for NAAQS Analysis

Pollutant	Averaging Period	Design Value $\mu g/m^3$	Monitor(s)	Year(s)
$PM_{2.5}$	24-hour	24.1	40-015-9008	2009-2011
	Annual	9.2	40-015-9008	2009-2011
NO_2	1-hour	38.5	40-(001 & 135)	2009-2011
	Annual	39.0	40-109-1037	2011

iii) Ozone (O_3)

Pre-construction monitoring for ozone is required for any new source or modified existing source located in an unclassified or attainment area with greater than 100 tons per year of VOC or NOx emissions. Continuous ozone monitoring data must be used to establish existing air quality concentrations in the vicinity of the proposed source or modification.

In accordance with the "Ambient Monitoring Guidelines for Prevention of Significant Deterioration", EPA-450/4-87-007, existing monitoring data can be used to meet this requirement. The existing monitoring data should be representative of three types of areas: (l) the location(s) of maximum concentration increase from the proposed source or modification, (2) the location(s) of the maximum air pollutant concentration from existing sources, and (3) the location(s) of the maximum impact area, i.e., where the maximum pollutant concentration would hypothetically occur based on the combined effect of existing sources and the proposed new source or modification.

The locations and size of the three types of areas are determined through the application of air quality models. The areas of maximum concentration or maximum combined impact vary in size and are influenced by factors such as the size and relative distribution of ground level and elevated sources, the averaging times of concern, and the distances between impact areas and contributing sources. In situations where there is no existing monitor in the modeled areas, monitors located outside these three types of areas may be used. Each determination must be made on a case-by-case basis. The EPA guidance on this issue is not designed for the evaluation of a secondary pollutant like ozone and the guidance document clearly discusses the evaluation of the impact of primary pollutants. However, a demonstration that existing monitoring data for ozone is representative of the three areas listed above can be made.

The facility is located in a rural area, Woods County, ten miles southwest of Alva, Oklahoma, with a population density of 6.9 people per square mile. The emission density reflects a lack of population and industrial development. Based on the most recent triennial emission inventory, the NOx emission density for Woods County is 4.46 tons per square mile. The VOC emission density is 7.45 tons per square mile. There are two major sources of NOx within 10 miles of the facility. The terrain is flat. The nearest ozone monitor is in Dewey County (ID 400430860) 60-km SSW of the facility. This monitor is located in a similarly rural area, with similar emission densities (located within 5-km of three major oil and gas facilities), and similar climate and terrain.

Monitor	2009 4th High	2010 4th High	2011 4th High	Design Value
400430860	0.067 ppm	0.067 ppm	0.078 ppm	0.070 ppm

Projected emissions are 132.55 tons per year of VOC and 185.70 tons per year of NOx. Given source parameters, local emission densities, and baring the likelihood of ozone scavenging, any resultant ozone concentration increases are likely to be near the facility and nominal. The existing regional monitors are adequate to establish existing ozone concentration for the facility and its impact area. Given emission levels from the facility, local emission inventories, and the fact that current models would be inadequate to provide reasonably accurate assessments of the impact of such a small source, no further analyses are warranted.

6. Refined Modeling Analysis Results

i) $PM_{2.5}$

Based on EPA's guidance "Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS" dated March 23, 2010, the five year average of the modeled highest 1st high (H1H) 24-hour average impact was used to demonstrate compliance with the 24-hour standard and the five year average annual maximum modeled impacts was used to demonstrate compliance with the annual standard. The modeled impacts were added to the background to demonstrate compliance with the NAAQS. All sources were assumed to be increment consuming sources.

NAAQS Compliance Demonstration

Pollutant	**Averaging Period**	**Design Value $\mu g/m^3$**	**Impacts $\mu g/m^3$**	**Total $\mu g/m^3$**	**NAAQS $\mu g/m^3$**
$PM_{2.5}$	24-hour	24.1	4.75	29.1	35
	Annual	9.2	0.65	10.1	15

The facility exceeds the PSD significance level for direct emission of $PM_{2.5}$. In addition, the facility exceeds the NO_X significance level (40 TPY) and NO_X is a precursor for the formation of secondary $PM_{2.5}$. Therefore, refined modeling analysis was performed to evaluate both direct and secondary $PM_{2.5}$ emissions from the proposed facility. Since the H1H was used to model compliance with the NAAQS rather than the highest 8th high (H8H), the difference between the two values is what was assigned to the secondary formation of $PM_{2.5}$ within the modeling domain. Based on the difference between these two values, secondary formation from the facility was attributed a value of 1.8 $\mu g/m^3$. If we assume a conservative NO_3/NO_X ratio of 1:100, then secondary formation of $PM_{2.5}$ would amount to approximately 2.42 TPY which would have an estimated impact of 0.59 $\mu g/m^3$ which is accounted for by using the H1H rather than the design value from the modeling. Also, since the maximum impact in the modeling domain, which occurs at the facility fenceline, is used to determine compliance with the NAAQS for the whole domain, and secondary formation is expected to occur much farther from the facility, the analysis of secondary formation using the H1H is adequate enough to account for secondary formation of $PM_{2.5}$ from the proposed facility.

Available monitoring data was complete and adequate enough to account for formation of secondary $PM_{2.5}$ emissions because it is "within the time period that maximum pollutant concentrations would occur" and within a similar rural area with similar emission densities, climate, and terrain. Not to mention that some consideration should be given to the potential for some double counting of the impacts from modeled emissions that may be reflected in the background monitoring.

Given emission levels from the facility and local emission inventories no further analyses of secondary formation were warranted.

The following table presents a comparison of facility impacts and Class II increment.

Class II Increment Compliance Demonstration

Pollutant	Averaging Period	Impacts $\mu g/m^3$	Increment $\mu g/m^3$
$PM_{2.5}$	24-hour	3.29	18
	Annual	0.41	8

The major source baseline date for $PM_{2.5}$ is October 20, 2011. All modifications at major sources after the major source baseline date consume increment. The submittal of this permit triggered the minor source baseline date. The minor source baseline date is the date after which all minor sources or minor modifications consume increment. The $PM_{2.5}$ baseline areas are defined by county within each Air Quality Control Region (AQCR). Therefore, this permit triggered the minor source baseline date for $PM_{2.5}$ for Woods County within AQCR 187. The only major source that has been modified after October 20, 2011, is the Atlas Pipeline Midcontinent WESTOK, LLC Waynoka Natural Gas Processing Plant. All increment consuming sources from the Waynoka Gas Plant and the new sources from the Rose Valley Gas Plant were modeled at their potential to emit to determine the amount of increment consumed.

ii) **<u>NO_2</u>**

NO_2 modeling is usually done in Tiers. The first Tier is 100% conversion of NO_X to NO_2. The second Tier utilizes the Ambient Ratio Method which predicts 80% conversion of NO_X to NO_2. The third Tier is a case-by-case analysis of NO_X conversion utilizing either the Ozone Limiting Method (OLM) or the Plume Volume Molar Ratio Method (PVMRM). In these methods, the in-stack ratio of NO_2 to NO_X is utilized to help determine the total conversion of NO_X to NO_2. A facility can use all of methods mentioned above or just one of those methods to determine facility impacts for the SIL, NAAQS, and Increment. Modeling for the new 1-hour standard should comply with the EPA's guidance "General Guidance for Implementing the 1-hour NO_2 NAAQS in PSD permits, Including the Interim 1-hour NO_2 SIL" dated June 28, 2010. Modeling for the annual NAAQS and Increment are still required since these standards have not been vacated.

The facility did not show compliance using Tier I or Tier II analyses. Therefore, compliance with the 1-hour NAAQS was done utilizing a Tier III analysis and PVMRM. The Tier III analysis required a modeling protocol and pre-approval. The protocol was submitted to EPA on May 8, 2012, by AQD. The protocol was approved by AQD.

In the original modeling submittal, an in-stack ratio of 0.2 was used for all sources and all of the modeled impacts plus background were below the 1-hour NO_2 NAAQS (188 μg/m^3). The equilibrium ratio was set at 0.9. For the PVMRM analysis, hourly ozone data from the area is input into AERMOD which it then uses to predict the conversion of NO_X to NO_2. The ozone data was the hourly data from the nearest ozone monitor located in Seiling, Oklahoma and was from the same years as those for the modeling. For the increment analysis, all sources were assumed to be increment consuming sources. For the revised Tier III analysis, the in-stack ratio for each source was evaluated and set at the levels listed below.

In-Stack NO_2/NO_X Ratios

Source Type	**Ratio**
4SLB Engines	0.35
2SLB Engines	0.50
4SRB Engines	0.05
Turbines	0.20
Heaters/Boilers	0.10

Using the revised in-stack ratios, the modeled impacts of the nearby sources plus background did exceed the 1-hour NO_2 NAAQS. The list of violations and impacts from the nearby sources and the proposed source is shown below. Based on the modeling analysis, the impacts from the proposed facility did not cause or contribute to a violation of the NAAQS. Impacts from the proposed facility, at the receptors where a violation was predicted, were significantly below the interim significant impact level (7.5 μg/m^3). After the 25th highest high there were no more predicted violations of the NAAQS.

NAAQS Compliance Demonstration

Pollutant	**Averaging Period**	**Design Value μg/m^3**	**Impacts μg/m^3**	**Total μg/m^3**	**NAAQS μg/m^3**
NO_2	1-hour	38.5	259.41	297.91	188
	Annual	39.0	45.70	84.70	100

Predicted Violations of the NAAQS in the Area Modeled

	X	Y	Concentration (μg/m^3) at Each Rank Shown								
#	(m)	(m)	H8H	H9H	H10H	H11H	H12H	H13H	H14H	H15H	H16H
1	525742.5	4062653.3	168.84	166.70	160.53	154.44					
2	525742.5	4063153.3	155.69	154.18	152.29						
3	526242.5	4062153.3	152.21	151.43							
4	526242.5	4063153.3	161.71	153.95							
5	526742.5	4062153.3	156.14	150.63							
6	527242.5	4061653.3	170.25	165.48	164.01	162.32	156.10	150.70			
7	527242.5	4062153.3	176.83	172.74	170.10	163.08	160.70	158.96	156.03	151.46	
8	524595.4	4065028.3	150.21								
9	524595.4	4065653.3	162.13	157.81	150.26						
10	525330.8	4064403.3	152.30								
11	525330.8	4065028.3	167.59	163.60	158.16	156.15					
12	525330.8	4065653.3	170.94	165.73	161.88	157.62	156.20	152.91			
13	526066.0	4065028.3	158.58	153.68	149.89						
14	526066.0	4065653.3	161.24	157.95	155.75	152.45					
15	526801.3	4065653.3	167.35	163.44	154.58	151.48					
16	527536.6	4063778.3	200.26	190.91	185.02	181.84	178.81	169.36	165.11	160.42	157.8
17	527536.6	4064403.3	259.41	253.69	245.05	243.22	235.33	230.70	222.31	220.10	216.7
18	527536.6	4065028.3	158.40	157.19	154.24	151.69	150.45	152.23	149.87		
19	527536.6	4065653.3	168.79	165.01	160.10	158.59	155.40				
20	529742.5	4064403.3	184.51	173.36	169.45	156.51	150.67				
21	528492.5	4062418.0	173.15	165.40	162.46	155.52	152.28				
22	528492.5	4061682.8	174.88	169.96	162.52	155.30					
23	529117.5	4062418.0	162.46	159.47	155.55	150.30					
24	529117.5	4061682.8	159.67	156.73	152.01						
25	529117.5	4060947.3	149.63								
26	529742.5	4062418.0	151.94								
27	529742.5	4061682.8	151.88								
28	524464.8	4066486.5	154.36	151.52							
29	524464.8	4067320.0	150.90								
30	525436.9	4066486.5	158.13	153.15	152.37						
31	526409.2	4066486.5	164.46	160.82	158.93	156.63	155.71	154.06	152.07	151.31	
32	526409.2	4067320.0	171.78	166.08	162.97	160.77	160.41	159.14	157.53	153.63	151.20
33	527381.4	4066486.5	208.84	206.04	201.29	198.40	194.36	189.76	187.04	184.92	182.47
34	527381.4	4067320.0	165.44	162.44	158.86	157.48	154.38	151.62			
35	528353.6	4066486.5	161.01	156.26	152.08						
36	530575.8	4064681.0	169.18	163.74	157.36	154.32					
37	530575.8	4063708.8	162.59	156.65	153.71						
38	531409.2	4064681.0	164.36	158.92	155.83	152.54	150.35				
39	531409.2	4063708.8	159.09	150.32							

	X	Y	Concentration (μg/m³) at Each Rank Shown								
#	**(m)**	**(m)**	**H8H**	**H9H**	**H10H**	**H11H**	**H12H**	**H13H**	**H14H**	**H15H**	**H16H**
40	532242.5	4064681.0	153.98	151.50							
41	532242.5	4063708.8	158.85	151.75	150.06						

All impacts from the Rose Valley Gas Plant at the receptors which have potential violations are less than 0.1 μg/m^3. The violations were isolated to four receptors by the highest 17th high and to no more violations after the highest 25th high. The noted violations are centered around and are due to a single source: Panhandle Eastern Pipeline Company's Alva N Hopeton Compressor Station. In summary, even though the modeling showed violations within the region investigated, the proposed facility does not contribute meaningfully (impacts are less than less than 0.1 μg/m^3) to those violations.

The NO_2 annual increment consumed was 20.97 μg/m^3, assuming 100% conversion of NO_X to NO_2. Using a Tier II analysis, the ambient ratio method (ARM) with 75% conversion, the increment consumed would be 20.97 μg/m^3. Using either method, the increment consumed is less than the 25 μg/m^3 standard.

Increment Compliance Demonstration [1]

Pollutant	**Averaging Period**	**Impacts μg/m³**	**Increment μg/m³**
NO_2	Annual	20.97	25

[1] Calculated using 100% NO_X to NO_2 conversion.

D. <u>Additional Impacts Analysis</u>

An additional impacts analysis considering existing air quality, the quantity of emissions, and the sensitivity of local soils, vegetation, and visibility in the source's impact area was performed and the following are addressed:

- Class I Area Impacts
- Class II Area Visibility Impacts
- Growth Impacts
- Soil and Vegetation Impacts

1. <u>Class I Area Impacts Analysis</u>

A further requirement of PSD includes the special protection of air quality and air quality related values (AQRV) at potentially affected nearby Class I areas. Assessment of the potential impact to visibility (regional haze analysis) is required if the source is located within 100 km of a Class I area. An evaluation may be requested if the source is within 200 km of a Class I area. The facility is approximately 207 km (126.8 miles) north of the Wichita Mountain Wildlife Class I area.

The following is an excerpt from the Federal Land Managers' Air Quality Related Values Work Group (Flag), Phase I Report – Revised (2010), Section 3.2 Initial Screening Criteria (New):

> *"…the Agencies will consider a source locating greater than 50 km from a Class I area to have negligible impacts with respect to Class I AQRVs if its total SO_2, NO_X, PM_{10}, and H_2SO_4 annual emissions (in tons per year, based on 24-hour maximum allowable emissions), divided by the distance (in km) from the Class I area (Q/D) is 10 or less. The Agencies would not request any further Class I AQRV impact analyses from such sources."*

The total emissions for SO_2, NO_X, PM_{10}, and H_2SO_4 at the facility sum to 152.64 TPY. Therefore, the Q/D value is 0.74 which is less than 10 and no further Class I AQRV impacts analyses are required.

For compliance with the Class I area increments, the maximum impacts at the closest receptor in the direction of the Class I area, 10 km south of the facility and approximately 197 km north of the Class I area, were taken and compared to the Increment.

Class I Increment Compliance Demonstration

	Averaging	**Impacts**	**Increment**	**SIL**
Pollutant	**Period**	**$\mu g/m^3$**	**$\mu g/m^3$**	**$\mu g/m^3$**
$PM_{2.5}$	24-hour	0.14	2.0	0.07
	Annual	0.006	1.0	0.06
NO_2	Annual	0.08	2.5	0.80

Modeled impacts for the $PM_{2.5}$ and NO_2 annual averaging periods were below their respective SIL. For the 24-hour $PM_{2.5}$ analysis, the impacts exceeded the SIL at a distance of 10 km from the site; however, the impacts were steadily declining. To confirm that the impacts would not exceed the SIL in the vicinity of the Class I area, facility impacts at additional receptors in the direction of the Class I area were analyzed. Those impacts are presented below.

Refined Class I Increment Compliance Demonstration
For the 24-hour PM2.5 Standard

	Averaging	**Impacts**	**Distance from Facility**	**Increment**	**SIL**
Pollutant	**Period**	**$\mu g/m^3$**	**km**	**$\mu g/m^3$**	**$\mu g/m^3$**
$PM_{2.5}$	24-hour	0.1356	10	2.0	0.07
		0.0480	20		
		0.0317	30		
		0.0317	40		
		0.0219	50		

As shown in the table, facility impacts are well below the SIL at a distance of 20 km from the site (a distance well over 180 km from the Class I Area). Due to terrain and weather records, the reduction in impact is not uniform with distance (and the highest impacts occur in different modeling years). However, the reduction in impact is well below the SIL at a distance that is sufficiently protective of the Class I area.

2. Class II Area Visibility Impacts Analysis

Per the referenced AQD modeling guidance document, applicants proposing to construct PSD Major sources within 40 km of a Class II Sensitive area are required to use the VISCREEN model to address the visibility impacts within the Class II Sensitive Area. The facility is approximately 40.8 km west-southwest of the Great Salt Plains State Park, the closest Class II Sensitive Area to the facility. Therefore, no VISCREEN modeling was required.

3. Growth Impact Analysis

A growth analysis is intended to quantify the amount of new growth that is likely to occur in support of the facility and to estimate emissions resulting from that associated growth. Associated growth includes residential and commercial/industrial growth resulting from the new facility. Residential growth depends on the number of new employees and the availability of housing in the area, while associated commercial and industrial growth consists of new sources providing services to the new employees and the facility. No additional residential and commercial/industrial growth will result from the new facility since the facility will be located in an area that has an available population to supply employees.

4. Soil & Vegetation Impacts Analysis

The effects of gaseous air pollutants on vegetation may be classified into three rather broad categories: acute, chronic, and long-term. Acute effects are those that result from relatively short (less than 1 month) exposures to high concentrations of pollutants. Chronic effects occur when organisms are exposed for months or even years to certain threshold levels of pollutants. Long-term effects include abnormal changes in ecosystems and subtle physiological alterations in organisms. Acute and chronic effects are caused by the gaseous pollutant acting directly on the organism, whereas long-term effects may be indirectly caused by secondary agents such as changes in soil pH. It is expected that compliance with the primary and secondary NAAQS will ensure that emissions from the facility will not adversely affect vegetation or soils in the surrounding area.

SECTION V. EMISSIONS

A. Hopeton Plant (Existing)

The Hopeton Plant operates under Permit No. 2007-247-O (M-1). Permitted sources include a 3.35-MMBTUH hot oil heater, a process flare, two 1,000-bbl condensate storage tanks, condensate loading, and fugitive sources. Heater emissions were estimated using factors from AP-42 (7/98), Tables 1.4-2 and 1.4-3. Working and breathing tank emissions were estimated using the TANKS4.0 software. Flashing emissions were expected to be negligible, because the condensate is directed to a stabilizer where heat is added to boil off light hydrocarbons. The condensate stored in the tanks has a Reid Vapor Pressure (RVP) of approximately 11 psia. Truck loading emissions were estimated based on AP-42 (6/08), Section 5.2, and a throughput of 2,310,000 gallons per year. Flare emissions were estimated using AP-42 (1/95) factors for NO_x and CO. VOC emissions from the flare were estimated by summing the quantity of VOCs routed to the flare and using a 98% destruction efficiency. Fugitive VOC emissions were estimated based on EPA's 1995 *Protocol for Equipment Leak Estimates* (EPA-453/R-95-017).

The applicant included estimates of greenhouse gas (GHG) emissions from the existing equipment in their application. The CO_{2e} emissions from combustion of natural gas are based on the default factors for natural gas combustion from 40 CFR Part 98, Subpart C, Tables C-1 and C-2 and the related global warming potential factors from 40 CFR Part 98, Subpart A, Table A-1, yielding a combined CO_{2e} emission factor of 117 lb/MMBTU. All other CO_{2e} emissions are related to CO_2 or CH_4 emissions and the related global warming potential factor.

Facility-Wide NO_x, CO, and VOC Emissions for the Hopeton Plant
[From Permit No. 2007-247-O (M-1)]

	NO_X		CO		VOC	
Source	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
H-1	0.31	1.36	0.26	1.14	0.02	0.07
TK-1	---	---	---	---	---	6.35
TK-2	---	---	---	---	---	6.35
FLARE1	0.22	0.98	1.22	5.34	0.21	0.93
L-1 [1]	---	---	---	---	---	6.47
FUG [1]	---	---	---	---	1.97	8.62
Total Emissions	**0.53**	**2.34**	**1.48**	**6.48**	**2.20**	**28.79**

[1] It should be noted that L-1 and FUG will not remain as separate emissions sources for the Hopeton Plant once the Rose Valley Plant has been constructed.

Facility-Wide SO_2, $PM_{10}/PM_{2.5}$, and CO_{2e} Emissions for the Hopeton Plant

	SO_2		$PM_{10}/PM_{2.5}$		CO_{2e}	
Emission Unit	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
H-1	<0.01	0.01	0.03	0.12	392	1,717
TK-1	---	---	---	---	---	133
TK-2	---	---	---	---	---	133
FLARE1	<0.01	<0.01	<0.01	<0.01	34	149
Total Emissions	**<0.01**	**0.01**	**0.03**	**0.12**	**426**	**2,132**

B. Rose Valley Plant (New)

This permit authorizes the construction of the following new emissions sources: ten 1,775-hp Caterpillar G3606 engines equipped with oxidation catalysts, two 9,443-hp Siemens SGT-200-2S turbines, two 2,889-hp Caterpillar G3520C IM emergency generators with oxidation catalysts, two 5.605-MMBTUH regeneration heaters, two 17.4-MMBTUH hot oil heaters, four 1,000-bbl condensate storage tanks (with emissions controlled by an enclosed flare), four 400-bbl produced water tanks, two 20,000-bbl/day amine units, two 2.66-MMBTUH emergency flares, a 0.99-MMBTUH enclosed flare, loading of condensate and produced water into tanker trucks, and process piping and other fugitive sources.

The applicant estimated GHG emissions for the new equipment in the same manner described for the existing equipment located at the Hopeton plant: default factors for natural gas combustion from 40 CFR Part 98, Subpart C, Tables C-1 and C-2 and the related global warming potential factors from 40 CFR Part 98, Subpart A, Table A-1. Similarly, all other CO_{2e} emissions were estimated based on CO_2 or CH_4 emissions and the related global warming potential factor.

Emissions from the compressor engines and the emergency generator engines were estimated based on manufacturer's emission data for NO_X, CO and VOC and on factors from AP-42 (8/2000), Section 3.2 for $PM_{10/2.5}$. All of these engines are four-stroke, lean-burn engines equipped with oxidation catalysts. The compressor engines (1,775-hp Caterpillar G3606LE) were assumed to run continuously. The emergency generator engines (2,889-hp G3520C IM) were assumed to operate 750 hours per year. It should be noted that, even though the engines are referred to as emergency generator engines, because they are authorized for up to 750 hours of operation per year, they are more properly described as "limited use engines."

Engine Emission Factors

Name/Model	NO_X (g/hp-hr)	CO (g/hp-hr)	VOC (g/hp-hr)
1,775-hp Caterpillar G3606LE W/OC	0.50	0.36	0.13
2,889-hp Caterpillar G3520C IM W/OC	0.50	0.43	0.44

W/OC – with oxidation catalyst

Emission estimates from the turbines are based on manufacturer's emission data for NO_X, CO and VOC, AP-42 (4/2000), Section 3.1 emission factors for $PM_{10/2.5}$, and continuous operation.

Turbine Emission Concentrations

Pollutant	Concentration	lb/MMBTU [1]
NO_X	15.0 ppmvd @ 15% O_2	0.0550
CO	15.0 ppmvd @ 15% O_2	0.0335
VOC	10.0 ppmvd @ 15% O_2	0.0352

[1] Based on fuel a consumption rate of 81.13 MMBTUH (HHV)

Emission estimates from the heaters are based on manufacturer's data for NO_X for the Low-NO_X burners, the rated heat input, and AP-42 (7/1998), Section 1.4 emission factors for CO, VOC, $PM_{10/2.5}$, and SO_2. The heaters were assumed to operate continuously.

Heater Capacities and Emission Factors

Parameter	**Value**
Burner Capacity: H-2 and H-4	5.605 MMBTUH
Burner Capacity: H-3 and H-5	17.4 MMBTUH
Emission Factors	
NO_x	45 lb/MMscf
CO	84 lb/MMscf
VOC	5.5 lb/MMscf
SO_2	0.6 lb/MMscf
$PM_{10/2.5}$ Filt. + Cond.	7.6 lb/MMscf

Emissions of VOCs (working and breathing losses) from the four new 1,000-bbl condensate tanks were estimated using Tanks 4.0.9d and the condensate throughput, 1,533,000 gallons per year (100 barrels per day) for each tank. The condensate was assumed to be equivalent to RVP 10 gasoline. Because the condensate will be stabilized before being sent to the storage tanks, no flashing emissions will be associated with the condensate storage tanks. The tank emissions are controlled by an enclosed flare (EFL-1) with a 98% capture efficiency. Emissions of VOCs from the four new 400-bbl produced water tanks were estimated using Tanks 4.0.9d and the produced water throughput, 76,650 gallons per year (5 barrels per day) for each tank. The produced water was assumed to include 3.7% condensate. The water tank emissions are also controlled by an enclosed flare (EFL-1) with a 98% capture efficiency.

Emissions from loading stabilized condensate into tank trucks were estimated using AP-42 (1/95), Section 5.2, Equation 1, a saturation factor of 0.6. a vapor pressure of 5.39 psia, a vapor molecular weight of 66, a throughput of 4,599,000 gallons per year (per process train). Emissions from the condensate tanks are controlled by an enclosed flare (EFL-1). There are two process trains and one condensate truck loading emission unit for each process train (CL-1 and CL-2); emissions from both trains are controlled by the same enclosed flare (EFL-1). Emissions from loading produced water into tank trucks were estimated using AP-42 (1/95), Section 5.2, Equation 1, a saturation factor of 0.6, a vapor pressure of 0.285 psia, a vapor molecular weight of 19.8, a throughput of 153,000 gallons per year (per process train). There are two emission units (WL-1 and WL-2), one unit per process train, and both are controlled by the same enclosed flare (EFL-1).

Off-gases from the amine unit's still vent and flash tank were estimated using the ProMax process simulator. Each amine unit (of which there are two units, A-1 and A-2, one for each process train) will treat a hydrocarbon liquid process stream. The flow rate of the hydrocarbon liquid process stream (for each unit) will be 103,429 lb/hr. The pumping rate for the diethanolamine (DEA) solution (30%) will be 90 gallons per minute (gpm). The composition of the acid gas stream and flash tank stream were noted in the application. Emissions from the still vent will be uncontrolled. Emissions from the flash tank will be routed to fuel the amine unit reboiler or the hot oil heater, with a 95% control efficiency.

Emissions from the emergency flares (FLARE2 and FLARE3, one for each process train) and from the enclosed flare (EFL-1) were estimated by summing emissions associated with the flare pilot, combustion of purge gas, and combustion of hydrocarbons during emergency shutdowns and related events. In addition, these emissions units include uncaptured and captured but uncombusted VOCs from various process units (e.g., VOCs emitted from the condensate and produced water storage tanks). The flare capture efficiency is 98% and the combustion destruction efficiency is 98%. An exception is for the enclosed flare used to control condensate truck loading. For that application, the collection efficiency is 70%. Pilot and purge gases for the emergency flares will provide 210 scf/hr of fuel with a heat content estimated at 902 BTU/scf (1,001 BTU/scf HHV). For the enclosed flare, the volume of pilot gas and assist gas (used to ensure that the enclosed flare burns smokeless) is 833 scf/hr with a heat content estimated at 881 BTU/scf (978 BTU/scf HHV). Emissions of NO_x, CO, VOC, and $PM_{10/2.5}$ were estimated for the combustion of the pilot, purge, and assist gases using factors for small heaters from AP-42 (7/1998), Section 1.4. Emissions of SO_2 due to combustion of pilot, purge, and assist gases were estimated using a mass balance and assuming a fuel sulfur content of 1 grain of sulfur per 100 scf of fuel. Emissions of NO_x and CO associated with the combustion of fuel released during emergency events were estimated using factors for flares from AP-42 (1/95), Section 13.5, and a net fuel consumption rate of 2.66 MMBTUH (2.95 MMBTUH HHV) for each emergency flare and a net fuel consumption rate of 0.99 MMBTUH (1.10 MMBTUH HHV) for the enclosed flare.

Fugitive VOC emissions are based on estimated equipment counts, an estimated C_{3+} content, and average emission factors or emission screening values from EPA's *1995 Protocol for Equipment Leak Emission Estimates* (EPA-453/R-95-017).

Emissions from blowdowns were estimated using a volume of approximately 5.85 MMSCFY for compressors and ancillary equipment associated with the engines (BD) and approximately 1.62 MMSCFY for compressors and ancillary equipment associated with the turbines (BD2). In addition, the applicant used a speciated gas analysis to determine gas composition and molecular weight. Contributions for all propane-plus hydrocarbons were summed to determine blowdown VOC emissions. The total VOC content of the gas streams was determined to be approximately 11.98% by weight. The CO_2 content was 0.203% by volume and the CH_4 content was 76.15% by weight.

Facility-Wide NO_x, CO, and VOC Emissions for the Rose Valley Plant

	NO_X		CO		VOC [1]	
Sources	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
C-1	1.96	8.57	1.39	6.11	0.65	2.83
C-2	1.96	8.57	1.39	6.11	0.65	2.83
C-3	1.96	8.57	1.39	6.11	0.65	2.83
C-4	1.96	8.57	1.39	6.11	0.65	2.83
C-5	1.96	8.57	1.39	6.11	0.65	2.83
C-6	1.96	8.57	1.39	6.11	0.65	2.83
C-7	1.96	8.57	1.39	6.11	0.65	2.83
C-8	1.96	8.57	1.39	6.11	0.65	2.83
C-9	1.96	8.57	1.39	6.11	0.65	2.83
C-10	1.96	8.57	1.39	6.11	0.65	2.83
T-1	4.47	19.56	2.72	11.91	2.85	12.50
T-2	4.47	19.56	2.72	11.91	2.85	12.50
GEN-1	3.18	1.19	2.73	1.02	3.51	1.32
GEN-2	3.18	1.19	2.73	1.02	3.51	1.32
H-2	0.27	1.18	0.50	2.20	0.03	0.14
H-3	0.83	3.65	1.56	6.82	0.10	0.45
H-4	0.27	1.18	0.50	2.20	0.03	0.14
H-5	0.83	3.65	1.56	6.82	0.10	0.45
TK-3	---	---	---	---	---	0.14
TK-4, -5, -6	---	---	---	---	---	0.41
WT-1, -2	---	---	---	---	---	<0.01
WT-3, -4	---	---	---	---	---	<0.01
CL-1	---	---	---	---	---	3.53
CL-2	---	---	---	---	---	3.53
EFL-1	0.15	0.66	0.44	1.91	0.26	1.15
WL-1	---	---	---	---	---	0.01
WL-2	---	---	---	---	---	0.01
A-1	---	---	---	---	1.69	7.39
A-2	---	---	---	---	1.69	7.39
FLARE-2	0.20	0.88	1.00	4.39	0.01	0.04
FLARE-3	0.20	0.88	1.00	4.39	0.01	0.04
FUG	---	---	---	---	1.58	6.93
FUG2	---	---	---	---	1.56	6.85
BD	---	---	---	---	---	16.62
BD2	---	---	---	---	---	4.60
Total Emissions	**37.65**	**139.28**	**31.36**	**115.69**	**26.28**	**115.76**

[1] The VOC emissions in this table include formaldehyde. These inclusive VOC emissions estimates are appropriate for PSD significance and related determinations. Emissions inventory submissions will subtract formaldehyde to yield non-HAP VOCs.

Facility-Wide SO_2, $PM_{10}/PM_{2.5}$, and CO_{2e} Emissions for the Rose Valley Plant

	SO_2		$PM_{10}/PM_{2.5}$		CO_{2e}	
Sources	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
C-1	0.01	0.03	0.12	0.53	1,744	7,640
C-2	0.01	0.03	0.12	0.53	1,744	7,640
C-3	0.01	0.03	0.12	0.53	1,744	7,640
C-4	0.01	0.03	0.12	0.53	1,744	7,640
C-5	0.01	0.03	0.12	0.53	1,744	7,640
C-6	0.01	0.03	0.12	0.53	1,744	7,640
C-7	0.01	0.03	0.12	0.53	1,744	7,640
C-8	0.01	0.03	0.12	0.53	1,744	7,640
C-9	0.01	0.03	0.12	0.53	1,744	7,640
C-10	0.01	0.03	0.12	0.53	1,744	7,640
T-1	0.25	1.09	0.48	2.10	8,554	37,466
T-2	0.25	1.09	0.48	2.10	8,554	37,466
GEN-1	0.01	<0.01	<0.01	<0.01	3,071	1,151
GEN-2	0.01	<0.01	<0.01	<0.01	3,071	1,151
H-2	<0.01	0.02	0.05	0.20	656	2,872
H-3	0.01	0.05	0.14	0.62	2,036	8,917
H-4	<0.01	0.02	0.05	0.20	656	2,872
H-5	0.01	0.05	0.14	0.62	2,036	8,917
TK-3	---	---	---	---	---	<1
TK-4, -5, -6	---	---	---	---	---	<1
WT-1, -2	---	---	---	---	---	<1
WT-3, -4	---	---	---	---	---	<1
CL-1	---	---	---	---	---	4
CL-2	---	---	---	---	---	4
EFL-1	0.01	0.03	<0.01	<0.01	216	946
WL-1	---	---	---	---	---	<1
WL-2	---	---	---	---	---	<1
A-1	---	---	---	---	1,853	8,116
A-2	---	---	---	---	1,853	8,116
FLARE-2	<0.01	<0.01	<0.01	<0.01	385	1,686
FLARE-3	<0.01	<0.01	<0.01	<0.01	385	1,686
FUG	---	---	---	---	75	329
FUG2	---	---	---	---	73	318
BD	---	---	---	---	---	2,295
BD2	---	---	---	---	---	635
Total Emissions	**0.65**	**2.65**	**2.54**	**11.14**	**50,914**	**201,347**

Hazardous Air Pollutant Emissions (HAPs)

The primary hazardous air pollutant (HAP) emitted from the engines is formaldehyde (HCHO). The formaldehyde emission factors for both the Caterpillar G3606LE engines and the Caterpillar G3520C IM engines were provided by the engine manufacturer. Both engines are equipped with oxidation catalysts. The G3606LE engines were assumed to run 8,760 hr/yr and the G3520C IM engines will be limited to 750 hr/hr.

Controlled Formaldehyde Emissions from the Engines

			Factor [1]	%	Est. Emissions	
EU	**Source**	**Hp**	**g/hp-hr**	**Reduction**	**lb/hr**	**TPY**
C-1	Caterpillar G3606LE w/OC [2]	1,775	0.26	85	0.153	0.668
C-2	Caterpillar G3606LE w/OC	1,775	0.26	85	0.153	0.668
C-3	Caterpillar G3606LE w/OC	1,775	0.26	85	0.153	0.668
C-4	Caterpillar G3606LE w/OC	1,775	0.26	85	0.153	0.668
C-5	Caterpillar G3606LE w/OC	1,775	0.26	85	0.153	0.668
C-6	Caterpillar G3606LE w/OC	1,775	0.26	85	0.153	0.668
C-7	Caterpillar G3606LE w/OC	1,775	0.26	85	0.153	0.668
C-8	Caterpillar G3606LE w/OC	1,775	0.26	85	0.153	0.668
C-9	Caterpillar G3606LE w/OC	1,775	0.26	85	0.153	0.668
C-10	Caterpillar G3606LE w/OC	1,775	0.26	85	0.153	0.668
GEN-1	Caterpillar G3520C IM w/OC [3]	2,889	0.58	80	0.739	0.277
GEN-2	Caterpillar G3520C IM w/OC	2,889	0.58	80	0.739	0.277
	Totals [4]				**3.01**	**7.23**

1. These are uncontrolled factors. The emissions estimates include the control efficiencies shown.
2. w/OC = with oxidation catalyst.
3. The emissions estimates for the 2889-hp Caterpillar G3520C IM engines are based on 750 hours of operation per year.
4. Totals do not necessarily add up exactly due to rounding.

In addition to formaldehyde, the facility provided estimates of emissions of additional HAPs that are emitted by the facility and these additional HAPs, as well as the HAPs previously discussed, are included in the facility-wide HAP emissions table. Some of these HAPs (for example, acrolein) were estimated using AP-42 factors for combustion sources. Other HAPs (e.g., fugitive benzene emissions from process piping) were estimated based on a speciated gas analysis, showing the concentration of each HAP in the VOCs emitted by fugitive sources, tanks, and blowdowns. All of these HAPs were used to estimate the total HAPs emitted facility-wide.

Facility-Wide HAP Emissions (Controlled)

Pollutant	CAS Number	Estimated Emissions	
		lb/hr [1]	TPY
Acetaldehyde	75070	1.34	4.57
Acrolein	107028	0.82	2.80
Benzene	71432	0.07	0.39
Ethyl benzene	100414	0.01	0.06
Formaldehyde	50000	3.11	7.71
n-Hexane	110543	0.28	1.70
Methanol	67561	0.40	1.36
Toluene	108883	0.09	0.49
Total Xylenes	1330207	0.04	0.21
Other HAPs (non-specific)	--	0.37	1.36
Total HAPs		**6.53**	**20.65**

[1] The lb/hr emission estimates do not necessarily convert to the TPY quantities due to the non-continuous nature of some of the emission sources.

The facility-wide aggregate controlled HAP emissions (20.65 TPY) do not exceed the major source threshold of 25 TPY of all HAPs combined. Additionally, no single HAP exceeds the 10 TPY threshold. Therefore, the facility is not a major source of HAPs. However, the facility is a "synthetic minor" source of HAPs, because the uncontrolled HAP emissions exceed the major source thresholds.

SECTION VI. INSIGNIFICANT ACTIVITIES

The insignificant activities identified and justified in the application are listed below. Records are available to confirm the insignificance of the activities. Record keeping for activities indicated with "*" is required in the Specific Conditions.

1. * Storage tanks with less than or equal to 10,000 gallons capacity that store volatile organic liquids with a true vapor pressure less than or equal to 1.0 psia at maximum storage temperature. There lube oil and amine storage tanks on the site. The vapor pressures for lube oil and amine are less than 1.0 psia.

2. * Emissions from storage tanks constructed with a capacity of less than 39,894 gallons and a true vapor pressure less than 1.5 psia at maximum storage temperature. Lube oil and amine storage tanks may fall into this category.

3. * Activities having the potential to emit no more than 5.0 TPY of any criteria pollutant. VOC emissions from the produced water tanks.

SECTION VII. OKLAHOMA AIR QUALITY RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-2 (Incorporation by Reference) [Applicable]
This subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. At this time, all of Oklahoma is in attainment of these standards.

OAC 252:100-5 (Registration of Air Contaminant Sources) [Applicable]
Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. The owner/operator will be required to submit emissions inventories and pay the appropriate fees.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
Part 5 includes the general administrative requirements for part 70 permits. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean individual emission units that either are on the list in Appendix I (OAC 252:100) or whose actual calendar year emissions do not exceed the following limits:

- 5 TPY of any one criteria pollutant
- 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAP or 20% of any threshold less than 10 TPY for a HAP that the EPA may establish by rule

Emission limitations and operational requirements necessary to assure compliance with all applicable requirements for all sources are based on information in the application and the current operating permit or developed from the applicable requirements.

OAC 252:100-9 (Excess Emissions Reporting Requirements) [Applicable]
Except as provided in OAC 252:100-9-7(a)(1), the owner or operator of a source of excess emissions shall notify the Director as soon as possible but no later than 4:30 p.m. the following working day of the first occurrence of excess emissions in each excess emission event. No later than thirty (30) calendar days after the start of any excess emission event, the owner or operator of an air contaminant source from which excess emissions have occurred shall submit a report for each excess emission event describing the extent of the event and the actions taken by the owner or operator of the facility in response to this event. Request for affirmative defense, as described in OAC 252:100-9-8, shall be included in the excess emission event report. Additional

reporting may be required in the case of ongoing emission events and in the case of excess emissions reporting required by 40 CFR Parts 60, 61, or 63.

OAC 252:100-13 (Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Control of Emission of Particulate Matter) [Applicable]
This subchapter specifies a particulate matter (PM) emissions limitation of 0.6 lb/MMBTU from fuel-burning equipment with a rated heat input of 10 MMBTUH or less. For external combustion units burning natural gas, AP-42, Table 1.4-2 (7/98), lists the total PM emissions for natural gas to be 7.6 lb/MMft^3 or about 0.0076 lb/MMBTU.

For fuel-burning equipment rated less than 1,000 MMBTUH but greater than 10 MMBTUH, the allowable PM emissions are calculated using the formula: $E = 1.042808\ X^{(-0.238561)}$, where E is the limit in lb/MMBTU and X is the maximum heat input. The table below lists the fuel-burning equipment greater than 10 MMBTUH and their applicable emission limits.

Equipment	**Max. Heat Input (MMBTUH) (HHV)**	**Allowable PM Emission Rate (lb/MMBTU) (HHV)**	**Potential PM Emissions (lb/MMBTU) (HHV)**
1,775-hp Caterpillar G3606LE	13.43	0.561	0.0100
9,443-hp Siemens SGT-200-2S	81.15	0.365	0.0066
2,889-hp Caterpillar G3520C IM	17.88	0.524	0.0100
Hot Oil Heater	17.40	0.528	0.0076

For four-cycle lean-burn engines burning natural gas, AP-42 (7/00), Section 3.2, lists the total PM emissions as 0.00999 lb/MMBTU. For turbines burning natural gas, AP-42 (4/00), Section 3.1, lists the total PM emissions as 0.0066 lb/MMBTU. The permit requires the use of natural gas for all fuel-burning equipment to ensure compliance with Subchapter 19

This subchapter also limits emissions of particulate matter from industrial processes and direct-fired fuel-burning equipment based on their process weight rates. Since there are no significant particulate emissions from the non-fuel-burning processes at the facility compliance with the standard is assured without any special monitoring provisions.

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences that consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. When burning natural gas, there is very little possibility of exceeding these standards. This permit requires the use of natural gas for all fuel-burning units to ensure compliance with Subchapter 25.

OAC 252:100-29 (Control of Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. Under normal operating conditions, this facility has negligible potential to violate this requirement; therefore, it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air concentration of hydrogen sulfide (H_2S) emissions from any new or existing source to 0.2 ppmv (24-hour average) which is equivalent to 279 $\mu g/m^3$. The speciated gas analysis provided by the applicant shows no detectable H_2S in the inlet gas streams. However, the applicant intends to bring in other supplies of natural gas for processing and it is possible that the new sources will have detectable H_2S concentrations. To ensure compliance with this part (and to ensure compliance with Part 5 of this subchapter as discussed below), the applicant has accepted a permit limit of 0.41 ppmv in the inlet gas. This inlet gas H_2S concentration was incorporated into modeling, using AERSCREEN (Version 11126), to confirm that the ambient air impacts from the facility would comply with the 0.2 ppmv limit. Each still vent was modeled as having a stack air flow rate of 169 ACFM (10,140 ACFM) and an H_2S emission rate of 0.30 lb/hr. The maximum 24-hr impact from a single still vent was determined to be 6.246 $\mu g/m^3$ for a combined impact (both units) of 12.5 $\mu g/m^3$ which is below the 279 $\mu g/m^3$ limit.

Part 5 limits sulfur dioxide emissions from new petroleum or natural gas process equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb/MMBTU heat input averaged over 3 hours. For fuel gas having a gross calorific value of 1,000 Btu/SCF, this limit corresponds to fuel sulfur content of 1,203 ppmv. Gas produced from oil and gas wells having 343 ppmv or less total sulfur will ensure compliance with Subchapter 31. The permit requires the use of pipeline-grade natural gas or field gas with a maximum sulfur content of 343 ppmv for all fuel-burning equipment to ensure compliance with Subchapter 31.

Part 5 also limits hydrogen sulfide (H_2S) emissions from new petroleum or natural gas process equipment (constructed after July 1, 1972). Removal of H_2S in the exhaust stream, or oxidation to sulfur dioxide (SO_2), is required unless H_2S emissions from a single unit do not exceed 0.3 lb/hr for a two-hour average. If a unit exceeds this rate, H_2S emissions must reduced by a minimum of 95% of the H_2S in the exhaust gas. Direct oxidation of H_2S is allowed for units whose emissions would be less than 100 lb/hr of SO_2 for a two-hour average.

To ensure compliance with this subchapter, the applicant has accepted an inlet gas H_2S limit of 0.41 ppmv. The applicant submitted output from a PromMax (Version 3.2.11188.0) simulation demonstrating that, with an inlet concentration of 0.41 ppmv H_2S and a flow rate of 230 MMSCFD (per train), the H_2S emissions from each still vent would be 0.287 lb/hr. The permit requires the applicant to test the gas entering the facility to determine the H_2S concentration. Monitoring may be performed using a stain tube, an electronic H_2S monitor, or another method approved by AQD. Alternatively, an online analyzer may be used to measure the H_2S concentration in the gases exhausted by the still vent (with a limit of 245 ppmv).

OAC 252:100-33 (Nitrogen Oxides) [Not Applicable]
This subchapter limits new gas-fired fuel-burning equipment with rated heat input greater than or equal to 50 MMBTUH to emissions of 0.2 lb of NO_X per MMBTU, three-hour average. The turbines exceed the 50 MMBTUH threshold. Emissions of NO_X from the turbines are approximately 0.06 lb/MMTBU which is in compliance with this subchapter. Compliance with the BACT emission limits will ensure compliance with this subchapter.

OAC 252:100-35 (Carbon Monoxide) [Not Applicable]
None of the following affected processes are located at this facility: gray iron cupola, blast furnace, basic oxygen furnace, petroleum catalytic cracking unit, or petroleum catalytic reforming unit.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. The stabilized condensate tanks are subject to this subchapter and are equipped with an organic vapor recovery system.
Part 3 requires VOC loading facilities with a throughput greater than 40,000 gallons per day to be equipped with a vapor-collection and disposal system. The capacity of the facility (which, for both process trains combined, equals 9,198,000 gallons per year or 25,200 gallons per day) will be below this threshold.
For facilities with a throughput of 40,000 gallons per day or less, the facility must be equipped for submerged fill installed and operated to maintain a 97% submergence factor. This requirement has been subsumed by the BACT analysis which requires that the condensate loading operation be controlled by an enclosed flare. The tanker trucks will be bottom filled or will have submerged fill; vapors that evolve during loading will be piped to the enclosed flare.
Part 5 limits the VOC content of coatings from any coating line or other coating operation. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is exempt.
Part 7 requires fuel-burning and refuse-burning equipment to be operated and maintained so as to minimize VOC emissions. Temperature and available air must be sufficient to provide essentially complete combustion.
Part 7 requires all effluent water separators openings or floating roofs to be sealed or equipped with an organic vapor recovery system. There are no effluent water separators located at this facility.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
This subchapter regulates toxic air contaminants (TAC) that are emitted into the ambient air in areas of concern (AOC). Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained unless a modification is approved by the Director. Since no Area of Concern (AOC) has been designated anywhere in the state, there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

The following Oklahoma Air Quality Rules are not applicable to this facility:

OAC 252:100-11	Alternative Emissions Reduction	not eligible
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Grain, Feed, or Seed Facility	not in source category
OAC 252:100-39	Non-attainment Areas	not in a subject area
OAC 252:100-47	Municipal Solid Waste Landfills	not type of source category

SECTION VIII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
Total potential emissions of greenhouse gases (GHG) are greater than the major source threshold of 100,000 TPY of carbon dioxide equivalent (CO_{2e}). As a result, this permitting action must include a PSD review. This permitting action will also result in increases in emissions in excess of PSD significance thresholds for the following pollutants: NOx, CO, VOCs, $PM_{2.5}$, and CO_{2e}. The PSD review is in Section IV. Any future increases of emissions must be evaluated for PSD if they exceed a significance level (40 TPY NO_X, 100 TPY CO, 40 TPY VOC, 40 TPY SO_2, 25 TPY PM_{10}, 10 TPY $PM_{2.5}$, and 75,000 TPY CO_{2e}).

NSPS, 40 CFR Part 60 [Subparts A, Dc, Kb, JJJJ, KKKK, and OOOO Applicable]
Subpart A, General Provisions. This subpart contains requirements for flares used to comply with applicable subparts of parts 60 and 61 that specifically refer to this subpart. Design and monitoring requirements are included, as well as general notification and reporting requirements.
Subpart Dc, Small Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam-generating units constructed after June 9, 1989, and with capacity between 10 and 100 MMBTUH. The amine unit regeneration heaters have capacities below the regulatory threshold.

The hot oil heaters are used to heat a heat transfer medium which is used to heat hydrocarbons for partial fractionation in the demethanizers. Because the hot oil heaters heat a heat transfer medium, they are defined as “steam generating units” under this subpart. These units will combust only natural gas and will be subject only to the recordkeeping requirements of this subpart. These requirements have been included in the permit.

Subpart GG, Stationary Gas Turbines. This subpart affects stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBTUH, based on the LHV of the fuel fired which commence construction, modification, or reconstruction after October 3, 1977, but on or before February 18, 2005. The turbines which will be installed at this facility will be constructed after February 18, 2005, and they will be subject to NSPS, Subpart KKKK.

Subpart Kb, VOL Storage Vessels. This subpart regulates hydrocarbon storage tanks larger than 19,813-gal capacity and built after July 23, 1984. The four 1,000-bbl condensate tanks which will be installed at the site will be subject to this subpart. This subpart requires owners or operators of tanks storing a VOL to equip each storage vessel with either (a) a fixed roof in combination with an internal floating roof, (b) an external floating roof, or (c) a closed vent system and control device. The applicant has elected to comply by using a closed vent system to collect VOC vapors and direct them to an enclosed flare. The applicant will be required to confirm that there are no detectable emissions (using instrument readings and through visual inspections). The enclosed flare must reduce inlet VOC emissions by 95% and must abide by the specifications described in the general control device requirements (§60.18) of the General Provisions. These requirements have been incorporated into the permit.

Subpart KKK, Equipment Leaks of VOC from Onshore Natural Gas Processing Plants for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or before August 23, 2011. The new equipment will be constructed after August 23, 2011 and will be subject to the requirements of NSPS, Subpart OOOO.

Subpart LLL, Onshore Natural Gas Processing: SO_2 Emissions for which construction, reconstruction, or modification commenced after January 20, 1984, and on or before August 23, 2011. The new equipment will be constructed after August 23, 2011 and, if subject at all, will be subject to the requirements of NSPS, Subpart OOOO.

Subpart IIII, Stationary Compression Ignition (CI) Internal Combustion Engines (ICE). This subpart affects CI ICE, that are not fire pump engines, which commenced construction after July 1, 2005, and were manufactured after April 1, 2006. There is no plan to install CI ICE at the site.

Subpart JJJJ, Stationary Spark Ignition Internal Combustion Engines (SI-ICE). This subpart promulgates emission standards for all new SI engines ordered after June 12, 2006 and all SI engines modified or reconstructed after June 12, 2006, regardless of size. Stationary SI internal combustion engine manufacturers who choose to certify their stationary SI ICE with a maximum engine power greater than or equal to 100-hp under the voluntary manufacturer certification program must certify those engines to the emission standards in Table 1 to this subpart. Owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 100-hp must comply with the emission standards in Table 1 to this subpart for their stationary SI ICE.

Emission Standards from Table 1, Subpart JJJJ, g/hp-hr (ppmvd @ 15% O_2)

Engine Type & Fuel	Max Power (hp)	Mfg. Date	NO_X	CO	VOC
Non-Emergency SI Natural Gas[1]	hp ≥ 500	7/1/2007	2.0 (160)	4.0 (540)	1.0 (86)
		7/1/2010	1.0 (80)	2.0 (270)	0.7 (60)

[1] - except lean burn 500 ≤ HP < 1,350

An initial notification is required only for owners and operators of engines greater than 500 HP that are non-certified. Owners or operators must demonstrate compliance with the applicable emissions limits according to one of the following methods:

- Purchase a certified engine and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions
- Purchasing a certified engine (that is not operated and maintained according to the manufacturer's emission-related written instructions) or a non-certified engine and maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions and for engines greater than 500-hp conduct an initial performance test within 1 year of engine startup and conduct subsequent performance testing every 8,760 hours or 3 years.

The ten 1,775-hp Caterpillar G3606LE engines and the two 2,889-hp Caterpillar G3520C IM engines are expected to be constructed after June 12, 2006 and are subject to this subpart. All applicable requirements have been incorporated into the permit.

Subpart KKKK, Stationary Combustion Turbines. This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBTU) per hour, based on the higher heating value of the fuel, that commenced construction, modification, or reconstruction after February 18, 2005. Stationary combustion turbines regulated under this subpart are exempt from the requirements of Subpart GG. New natural gas fired turbines with a heat input at peak load of > 50 MMBTUH and ≤ 850 MMBTUH must meet a NO_X emission limit of ≤ 25 ppmdv @ 15% O_2. Turbines are also subject to either the SO_2 emission limitation of § 60.4330(a)(1) (0.90 lb SO_2/MWhr) or the fuel sulfur content limitation of § 60.4330(a)(2) (0.060 lb SO_2/MMBTU). Owners or operators must operate and maintain each turbine in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction. Owners or operators must demonstrate compliance with the applicable NO_X emission limit by performing annual testing or through use of either continuous emission monitoring or continuous parameter monitoring. If the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specify that the total sulfur content for natural gas is ≤ 20 gr/100 SCF the owner or operator is exempt from monitoring the total sulfur content of the fuel. The new stationary combustion turbines are expected to have been constructed after the applicability date of this subpart and are subject to this subpart. The facility will use continuous parameter monitoring or continuous emission monitoring to demonstrate compliance with the NO_X standard. The facility will comply with the SO_2 standard by demonstrating that the fuel sulfur content does not exceed 20 gr/100 SCF. The permit will incorporate all applicable requirements.

Subpart OOOO, Crude Oil and Natural Gas Production, Transmission, and Distribution. This subpart was signed on April 17, 2012, and affects the following sources that commence construction, reconstruction, or modification after August 23, 2011:

1. Each single gas well;
2. Single centrifugal compressors using wet seals that are located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment;
3. Reciprocating compressors which are single reciprocating compressors located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment;
4. Single continuous bleed natural gas driven pneumatic controllers with a natural gas bleed rate greater than 6 SCFH, which commenced construction after August 23, 2011, located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment and not located at a natural gas processing plant;
5. Single continuous bleed natural gas driven pneumatic controllers which commenced construction after August 23, 2011, and is located at a natural gas processing plant;
6. Single storage vessels located in the oil and natural gas production segment, natural gas processing segment, or natural gas transmission and storage segment;
7. All equipment, except compressors, within a process unit at an onshore natural gas processing plant;
8. Sweetening units located at onshore natural gas processing plants.

For each reciprocating compressor the owner/operator must replace the rod packing before 26,000 hours of operation or prior to 36 months. If utilizing the number of hours, the hours of operation must be continuously monitored. The new compressors will be subject to this subpart and any other new or modified compressors will have to comply with this subpart.

Continuous bleed natural gas devices (pneumatic controllers) at a natural gas processing plant must have a bleed rate of zero. All new pneumatic controllers at this facility will have to comply with this subpart.

Storage vessels constructed, modified or reconstructed after August 23, 2011**,** with VOC emissions equal to or greater than 6 TPY must reduce VOC emissions by 95.0 % or greater. All new or modified storage vessels will have to comply with this subpart.

The group of all equipment, except compressors, within a process unit at a natural gas processing plant must comply with the requirements of NSPS, Subpart VVa, except as provided in §60.5401. All new or modified process units will have to comply with this subpart.

A sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream. A sour natural gas stream is defined as containing greater than or equal to 0.25 grains sulfur per 100 standard cubic feet or 4 ppmv. The new amine units are expected to process only sweet natural gas and, therefore, they are not expected to be subject to this subpart. However, the facility is expected to be connected with new sources of natural gas. The permit includes requirements for periodic testing of the gas that will be processed by these units. If the sulfur concentration of the gas exceeds 4 ppmv, the applicant will be required to abide by all applicable requirements of this subpart.

NESHAP, 40 CFR Part 61 [Not Applicable]
There are no emissions of any of the regulated pollutants: arsenic, asbestos, beryllium, benzene, coke oven emissions, mercury, radionuclides, or vinyl chloride except for trace amounts of benzene. Subpart J (Equipment Leaks of Benzene) concerns only process streams, which contain more than 10% benzene by weight. All process streams at this facility are below this threshold.

NESHAP, 40 CFR 63 [Subpart ZZZZ Applicable]
Subpart HH, Oil and Natural Gas Production Facilities. This subpart applies to affected emission points that are located at facilities that are major and area sources of HAP, and either process, upgrade, or store hydrocarbon liquids prior to custody transfer or that process, upgrade, or store natural gas prior to entering the natural gas transmission and storage source category. For purposes of this subpart natural gas enters the natural gas transmission and storage source category after the natural gas processing plant, if present. The only affected source at area sources are triethylene glycol (TEG) dehydration units and there are no such units planned for construction at the site. All dehydration will be accomplished by molecular sieves.

Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart affects any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions. Owners and operators of the following new or reconstructed RICE must meet the requirements of Subpart ZZZZ by complying with either 40 CFR Part 60 Subpart IIII (for CI engines) or 40 CFR Part 60 Subpart JJJJ (for SI engines):

1) Stationary RICE located at an area source;
2) The following Stationary RICE located at a major source of HAP emissions:
    i) 2SLB and 4SRB stationary RICE with a site rating of ≤ 500 brake HP;
    ii) 4SLB stationary RICE with a site rating of < 250 brake HP;
    iii) Stationary RICE with a site rating of ≤ 500 brake HP which combust landfill or digester gas equivalent to 10% or more of the gross heat input on an annual basis;
    iv) Emergency or limited use stationary RICE with a site rating of ≤ 500 brake HP; and
    v) CI stationary RICE with a site rating of ≤ 500 brake HP.

The new engines are subject to this subpart and will comply with this subpart by complying with NSPS, Subpart JJJJ. No further requirements apply for engines subject to NSPS under this part. It should be noted that a stationary RICE located at an area source of HAP emissions is new if construction commenced on or after June 12, 2006. All applicable requirements have been incorporated into the permit.

Subpart JJJJJJ, Industrial, Commercial, and Institutional Boilers. This subpart affects new and existing boilers located at area sources of HAP, except for gas-fired boilers. Boiler means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam or hot water. Gas fired boilers are defined as any boiler that burns gaseous fuel not combined with any solid fuels, liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Because boilers are limited to heating of water the heaters and reboilers at this facility are not subject. Also, the boilers at this facility are gas fired.

Compliance Assurance Monitoring (CAM), 40 CFR Part 64 [Not Applicable]
This part applies to any pollutant-specific emission unit at a major source that is required to obtain an operating permit, for any application for an initial operating permit submitted after April 18, 1998, that addresses “large emissions units,” or any application that addresses “large emissions units” as a significant modification to an operating permit, or for any application for renewal of an operating permit, if it meets all of the following criteria:

- It is subject to an emission limit or standard for an applicable regulated air pollutant;
- It uses a control device to achieve compliance with the applicable emission limit or standard; and
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant greater than major source thresholds (100 TPY of a criteria pollutant, 10 TPY of a HAP, or 25 TPY of total HAP).

The engines are equipped with oxidation catalyst to comply with the applicable CO emission limits. However, the potential to emit CO for each engine is less than major source levels. Therefore, the engines are not subject to CAM. Emissions from the condensate tanks and condensate truck loading operations are controlled by an enclosed flare, but potential emissions are below major source thresholds. The amine unit flash tank emissions are controlled by routing those emissions to the hot oil heater (or another heater). Again, the potential emissions are below major source thresholds and, in addition, the use of those emissions as fuel exempts that source from CAM.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]
Naturally occurring hydrocarbon mixtures, prior to entry into a natural gas processing plant or a petroleum refining process unit, including: condensate, crude oil, field gas, and produced water, are exempt for the purpose of determining whether more than a threshold quantity of a regulated substance is present at the stationary source. This facility is not a natural gas processing plant as defined in §68.3(b) of 40 CFR Part 68. More information on this federal program is available on the web page: *www.epa.gov/ceppo*.

Stratospheric Ozone Protection, 40 CFR Part 82 [Not Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds

under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).
Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.

This facility does not produce, consume, recycle, import, or export any controlled substances or controlled products as defined in this part, nor does this facility perform service on motor (fleet) vehicles that involves ozone-depleting substances. Therefore, as currently operated, this facility is not subject to these requirements. To the extent that the facility has air-conditioning units that apply, the permit requires compliance with Part 82.

SECTION IX. COMPLIANCE

Tier Classification
This application has been determined to be Tier II based on the request for a construction permit for a new Part 70 source at a location currently permitted as a "true minor" facility. The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant (or applicant business) owns the land.

Public Review
The applicant published a "Notice of Filing a Tier II Application" in *The Alva Review-Courier* a semi-weekly newspaper in Woods County. The notice appeared in the newspaper on August 3, 2012. The notice stated that the application was available for public review at the Alva Public Library located at 504 Seventh Street, Alva, Oklahoma and that the application was also available for public review at the Air Quality Division main office. The applicant also published the "Notice of Draft Permit" in *The Alva Review-Courier*. The notice appeared on January 11, 2013. The notice stated that the draft permit was available for public review for a period of 30 days at the Alva Public Library and that the draft permit was also available for public review at the Air Quality Division main office and on the Air Quality section of the DEQ web page at *http://www.deq.state.ok.us*. No public comments were received during the 30-day comment period.

State Review
This facility is located within 50 miles of the Oklahoma - Kansas Border. The state of Kansas was notified of the draft permit. No comments were received from the state of Kanasas.

EPA Review

This permit was approved for concurrent public and EPA review. The draft was be forwarded to EPA for a 45-day review period. No public comments and, therefore, the draft permit was deemed the proposed permit. EPA did provide four comments. A summary of those comments and AQD responses to those comments is provided below.

1. EPA pointed out that the BACT analysis included in the draft/proposed permit did not distinguish between normal operation and startup, shutdown, and maintenance (SSM). EPA stated that, if compliance with normal BACT limits is not feasible, then secondary BACT limits for such periods should be established. In response, AQD added language in the BACT analysis section stating that the emission limits established in the permit apply to the units during SSM as well as during the normal operation of those units. Therefore, there is no need for secondary BACT limits or limitations on the number of SSM events. All the new units are expected to comply with BACT limits when averaged over the appropriate time frame.

2. EPA shared their concerns that the modeling used to demonstrate compliance with the one-hour and annual NO_2 NAAQS incorporated in-stack NO_2/NO_X ratio values that were lower than their recommended default value: 0.5. EPA also shared concerns about the different on-site and off-site values initially proposed in the modeling protocol submitted in support of the PSD application. AQD responded by clarifying that the same in-stack NO_2/NO_X ratios were used for on-site as well as off-site sources in the final Tier III NO_2 analysis used to demonstrate compliance with the NAAQS.

   In-Stack NO_2/NO_X Ratios
   On-Site and Off-Site Sources

Source Type	Ratio
4SLB Engines	0.35
2SLB Engines	0.50
4SRB Engines	0.05
Turbines	0.20
Heaters/Boilers	0.10

   EPA also stated that the use of lower in-stack NO_2/NO_X ratios must be justified to demonstrate that the lower ratios are acceptable and protective of the NAAQS. AQD responded that lower in-stack NO_2/NO_X ratios were justified based on data AQD has collected from similar sources and from published sources (e.g., AP-42). In addition, AQD has reviewed the results of recent engine test results and AQD is in the process of formatting those data into the format used by EPA in the proposed NO_2/NO_x In-Stack Ratio (ISR) Database. In short, the data available to AQD support the lower in-stack NO_2/NO_X ratios and it is AQD's finding that the ratios used in the revised Tier III NO_2 analysis are acceptable and are protective of the NAAQS.

3. EPA observed that the description of the modeling done to demonstrate compliance with the Class I Area PSD Increments for $PM_{2.5}$ and NO_2 focused on impacts from the applicant's

dispersion modeling on a receptor located approximately 10 km from the source and 197 km from the Class I Area. While the modeled impacts for the $PM_{2.5}$ and NO_2 annual averaging periods were lower than the corresponding SIL, for the 24-hour $PM_{2.5}$ analysis, the modeled impact at that (10 km) distance was above the SIL. EPA agreed with ODEQ that, based on the magnitude of these modeled impacts coupled with the additional distance to the Class I area, that the contributions from the proposed project would not be expected to impact compliance with the PSD Increment in the Class I area. However, EPA requested that additional analysis be incorporated into the memorandum justifying that finding. In response, AQD amended the modeling discussion to show that for receptors at distances 20, 30, 40, and 50 km from the facility, the modeled impacts are below the SIL. The amended language has been incorporated into this memorandum.

4. EPA shared their concurrence with AQD's assessment that ozone impacts associated with the proposed project would not be expected to cause or significantly contribute to violations of the ozone NAAQS based on monitored ambient ozone concentrations documented in the draft permit memorandum. AQD appreciates EPA's analysis and input.

Fees Paid

Part 70 source construction permit application fee of $7,500 for construction of a new Part 70 source at a location currently operating under a "true minor" permit.

SECTION X. SUMMARY

This facility has demonstrated the ability to comply with all Air Quality rules and regulations. Ambient air quality standards are not threatened at this site. There are no active Air Quality compliance or enforcement issues concerning this facility. Issuance of the construction permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Mid-America Midstream Gas Services, L.L.C. **Permit Number 2012-1393-C PSD**
Rose Valley Plant

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality and received on May 15, 2012, and additional information received subsequent to that date. The Evaluation Memorandum dated March 1, 2013, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction/continuing operations under this permit constitutes acceptance of, and consent to, the conditions contained herein.

1. Points of emissions and emissions limitations for each point: [OAC 252:100-8-34(b)]

EUG A. Natural Gas-Fired Reciprocating Internal Combustion Engines: Emission limitations have been established for EU C-1 through C-10 and include startup, shutdown, and maintenance (SSM). All other emissions were based on the heat input rating, AP-42 (7/98), Section 1.4, and a fuel sulfur content of 4 ppmv. Emission limitations for emission units (EU) C-1 through C-10:

			NO_X		CO		VOC	
EU	**Point**	**Engine Make/Model**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
C-1	C-1	1,775-hp Caterpillar G3606LE w/Oxidation Catalyst	1.96	8.57	1.39	6.11	0.65	2.83
C-2	C-2	1,775-hp Caterpillar G3606LE w/Oxidation Catalyst	1.96	8.57	1.39	6.11	0.65	2.83
C-3	C-3	1,775-hp Caterpillar G3606LE w/Oxidation Catalyst	1.96	8.57	1.39	6.11	0.65	2.83
C-4	C-4	1,775-hp Caterpillar G3606LE w/Oxidation Catalyst	1.96	8.57	1.39	6.11	0.65	2.83
C-5	C-5	1,775-hp Caterpillar G3606LE w/Oxidation Catalyst	1.96	8.57	1.39	6.11	0.65	2.83
C-6	C-6	1,775-hp Caterpillar G3606LE w/Oxidation Catalyst	1.96	8.57	1.39	6.11	0.65	2.83
C-7	C-7	1,775-hp Caterpillar G3606LE w/Oxidation Catalyst	1.96	8.57	1.39	6.11	0.65	2.83
C-8	C-8	1,775-hp Caterpillar G3606LE w/Oxidation Catalyst	1.96	8.57	1.39	6.11	0.65	2.83
C-9	C-9	1,775-hp Caterpillar G3606LE w/Oxidation Catalyst	1.96	8.57	1.39	6.11	0.65	2.83
C-10	C-10	1,775-hp Caterpillar G3606LE w/Oxidation Catalyst	1.96	8.57	1.39	6.11	0.65	2.83

BACT Limits

Name/Model	NO_X (g/hp-hr) [2]	CO (g/hp-hr) [2]	VOC (g/hp-hr) [2]	$PM_{2.5}$ (lb/MMBTU) [2, 3]	CO_{2e} (BTU/bhp-hr) [2, 4, 5]
1,775-hp Cat. G3606LE[1]	0.50	0.36	0.13	0.00999	≤ 8,452

[1] - with oxidation catalyst
[2] - Based on a three hour average.
[3] - Based on AP-42 (4/2000), Section 3.2.
[4] - Based on loads ≥ 50%.
[5] - Based on HHV

a. The engines shall only be fired with natural gas having a maximum sulfur content of 0.25 grains or less of total sulfur (as hydrogen sulfide) per 100 standard cubic feet (< 4 ppmv). Compliance can be shown by the following methods: for gaseous fuel, a current gas company bill, lab analysis, stain-tube analysis, gas contract, tariff sheet, or other approved methods. Compliance shall be demonstrated at least once every calendar year.
[OAC 252:100-31]

b. Each lean-burn engine shall be equipped with a properly functioning oxidation catalyst.
[OAC 252:100-8-6(a)(1)]

c. Each engine shall have a permanent identification plate attached that shows the make, model number, and serial number. [OAC 252:100-43]

d. At least once per calendar quarter, the permittee shall conduct tests of NO_X and CO emissions from the engine(s) and from each replacement engine/turbine when operating under representative conditions for that period. Testing is required for any engine/turbine that runs for more than 220 hours during that calendar quarter. A quarterly test may be conducted no sooner than 20 calendar days after the most recent test. Testing shall be conducted using a portable analyzer in accordance with a protocol meeting the requirements of the latest AQD Portable Analyzer Guidance document, or an equivalent method approved by Air Quality. When four consecutive quarterly tests show the engine/turbine to be in compliance with the emissions limitations shown in the permit, then the testing frequency may be reduced to semi-annual testing. A semi-annual test may be conducted no sooner than 60 calendar days nor later than 180 calendar days after the most recent test. Likewise, when the following two consecutive semi-annual tests show compliance, the testing frequency may be reduced to annual testing. An annual test may be conducted no sooner than 120 calendar days nor later than 365 calendar days after the most recent test. Upon any showing of non-compliance with emissions limitations or testing that indicates that emissions are within 10% of the emission limitations, the testing frequency shall revert to quarterly. Reduced testing frequency does not apply to engines with catalytic converters or oxidation catalyst. [OAC 252:100-8-6 (a)(3)(A)]

e. When periodic compliance testing shows engine exhaust emissions in excess of the lb/hr limits, the permittee shall comply with the provisions of OAC 252:100-9.
[OAC 252:100-9]

f. The owner/operator (O/O) shall comply with the Standards of Performance for Stationary Spark Ignition Internal Combustion Engine (SI-ICE), NSPS Subpart JJJJ, for all affected emission units, including but not limited to the following: [40 CFR §§ 60.4230-60.4248]

Emission Standards for O/O

i. § 60.4233 What emission standards must I meet if I am an O/O of a stationary SI-ICE?

ii. § 60.4234 How long must I meet the emission standards if I am an O/O of a stationary SI-ICE?

Other Requirements for O/O

iii. § 60.4236 What is the deadline for importing or installing stationary SI ICE produced in the previous model year?

iv. § 60.4237 What are the monitoring requirements if I am an O/O of an emergency stationary SI-ICE?

Compliance Requirements for O/O

v. § 60.4243 What are my compliance requirements if I am an O/O of a stationary SI-ICE?

Testing Requirements for O/O

vi. § 60.4244 What test methods and other procedures must I use if I am an O/O of a stationary SI-ICE?

Notification, Reports, and Records for O/O

vii. § 60.4245 What are my notification, reporting, and recordkeeping requirements if I am an O/O of a stationary SI-ICE?

General Provisions

viii. § 60.4246 What parts of the General Provisions apply to me?

EUG B. Natural Gas-Fired Turbines: Emission limitations have been established for EU T-1 and T-2 and include SSM. All other emissions were based on the heat input rating, AP-42 (4/2000), Section 3.1, and a fuel sulfur content of 4 ppmv.

EU	Point	Make/Model	hp
T-1	T-1	Siemens SGT-200-2S	9,443
T-2	T-2	Siemens SGT-200-2S	9,443

Emissions limits for each turbine (EU T-1 and T-2):

Pollutant	lb/hr	ppmvd [1]	TPY
NO_X	4.47 [2]	15.0 [2]	19.56
CO	2.72 [3]	15.0 [3]	11.91
VOC	2.85 [3]	10.0 [3]	12.50

[1] All concentrations are corrected to 15% O_2, per turbine. These concentration limits represent BACT for these units.

[2] One-hour average.

[3] Three-hour average.

BACT Limits

Pollutant	**lb/MMBTU**[1, 2]
$PM_{2.5}$	0.0066

[1] Based on AP-42 (4/2000), Section 3.1.
[2] Three-hour average.

BACT Limits

Pollutant	**BTU/bhp-hr**[1, 2, 3]
CO_{2e}	≤ 8,023

[1] Based on loads ≥ 75%.
[2] Based on LHV
[3] Three-hour average.

a. The turbines shall only be fired with natural gas having a maximum sulfur content of 0.25 grains or less of total sulfur (as hydrogen sulfide) per 100 standard cubic feet (< 4 ppmv). Compliance can be shown by the following methods: for gaseous fuel, a current gas company bill, lab analysis, stain-tube analysis, gas contract, tariff sheet, or other approved methods. Compliance shall be demonstrated at least once every calendar year. [OAC 252:100-31]

b. Each turbine shall have a permanent identification plate attached that shows the make, model number, and serial number. [OAC 252:100-43]

c. Each turbine shall be equipped and operated with NO_X CEM or CPM that complies with the requirements of NSPS, Subpart KKKK. [OAC 252:100-8-6(a)(3)]

d. When monitoring shows turbine exhaust emissions in excess of the limits, the permittee shall comply with the provisions of OAC 252:100-9. [OAC 252:100-9]

e. The turbines are subject to the NSPS for Stationary Combustion Turbines 40 CFR Part 60, Subpart KKKK and shall comply with all applicable requirements including but not limited to: [40 CFR § 60.4300 to § 60.4420]

<u>Introduction</u>

i. §60.4300 What is the purpose of this subpart?
ii. Applicability
iii. § 60.4305 Does this subpart apply to my stationary combustion turbine?
iv. § 60.4310 What types of operations are exempt from these standards of performance?

<u>Emission Limits</u>

v. § 60.4315 What pollutants are regulated by this subpart?
vi. § 60.4320 What emission limits must I meet for nitrogen oxides (NO_X)?
vii. § 60.4325 What emission limits must I meet for NO_X if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?
viii. § 60.4330 What emission limits must I meet for sulfur dioxide (SO_2)?

<u>General Compliance Requirements</u>

ix. §60.4333 What are my general requirements for complying with this subpart?

<u>Monitoring</u>

x. § 60.4335 How do I demonstrate compliance for NO_X if I use water or steam injection?

xi. § 60.4340 How do I demonstrate continuous compliance for NO_X if I do not use water or steam injection?
xii. § 60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?
xiii. § 60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?
xiv. § 60.4355 How do I establish and document a proper parameter monitoring plan?
xv. § 60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?
xvi. § 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?
xvii. § 60.4370 How often must I determine the sulfur content of the fuel?

<u>Reporting</u>

xviii. § 60.4375 What reports must I submit?
xix. § 60.4380 How are excess emissions and monitor downtime defined for NO_X?
xx. § 60.4385 How are excess emissions and monitoring downtime defined for SO_2?
xxi. § 60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?
xxii. § 60.4395 When must I submit my reports?

<u>Performance Tests</u>

xxiii. § 60.4400 How do I conduct the initial and subsequent performance tests, regarding NO_X?
xxiv. § 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?
xxv. § 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

<u>Definitions</u>

xxvi. § 60.4420 What definitions apply to this subpart?

EUG C. Emergency Use Natural Gas-Fired Reciprocating Internal Combustion Engines: Emission limitations have been established for EU GEN-1 and GEN-2 and include startup, shutdown, and maintenance (SSM). All other emissions were based on the heat input rating, AP-42 (7/98), Section 1.4, and a fuel sulfur content of 4 ppmv. It should be noted that these engines are authorized for up to 750 hours of operation per year and are properly described as "limited use engines" rather than as "emergency engines" under NSPS. Emission limitations for EU GEN-1 and GEN-2:

			NO_X		CO		VOC	
EU	**Point**	**Engine Make/Model**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
GEN-1	GEN-1	2,889-hp Caterpillar G3520C IM w/Oxidation Catalyst	3.18	1.19	2.73	1.02	3.51	1.32
GEN-2	GEN-2	2,889-hp Caterpillar G3520C IM w/Oxidation Catalyst	3.18	1.19	2.73	1.02	3.51	1.32

BACT Limits

Name/Model	NO_X (g/hp-hr) [2]	CO (g/hp-hr) [2]	VOC (g/hp-hr) [2]	$PM_{2.5}$ (lb/MMBTU) [2, 3]	CO_{2e} (BTU/bhp-hr) [2, 4, 5]
2,889-hp Caterpillar G3520C IM w/OC [1]	0.50	0.43	0.44	0.00999	≤ 8,212

1 - with oxidation catalyst
2 - Based on a three hour average.
3 - Based on AP-42 (4/2000), Section 3.2.
4 - Based on loads ≥ 50%.
5 - Based on HHV

a. The engines shall only be fired with natural gas having a maximum sulfur content of 0.25 grains or less of total sulfur (as hydrogen sulfide) per 100 standard cubic feet (< 4 ppmv). Compliance can be shown by the following methods: for gaseous fuel, a current gas company bill, lab analysis, stain-tube analysis, gas contract, tariff sheet, or other approved methods. Compliance shall be demonstrated at least once every calendar year. [OAC 252:100-31]

b. Each engine shall be equipped with a non-resettable hour meter. Each engine shall be operated for no more than 750 hours per 12-month period. For each emergency generator engine (or, more appropriately, "limited use engine"), the permittee shall record hours operated each month and calculate 12-month rolling totals.

c. Each lean-burn engine shall be equipped with a properly functioning oxidation catalyst. [OAC 252:100-8-6(a)(1)]

d. Each engine shall have a permanent identification plate attached that shows the make, model number, and serial number. [OAC 252:100-43]

e. At least once per calendar quarter, the permittee shall conduct tests of NO_X and CO emissions from the engine(s) and from each replacement engine/turbine when operating under representative conditions for that period. Testing is required for any engine/turbine that runs for more than 220 hours during that calendar quarter. A quarterly test may be conducted no sooner than 20 calendar days after the most recent test. Testing shall be conducted using a portable analyzer in accordance with a protocol meeting the requirements of the latest AQD Portable Analyzer Guidance document, or an equivalent method approved by Air Quality. When four consecutive quarterly tests show the engine/turbine to be in compliance with the emissions limitations shown in the permit, then the testing frequency may be reduced to semi-annual testing. A semi-annual test may be conducted no sooner than 60 calendar days nor later than 180 calendar days after the most recent test. Likewise, when the following two consecutive semi-annual tests show compliance, the testing frequency may be reduced to annual testing. An annual test may be conducted no sooner than 120 calendar days nor later than 365 calendar days after the most recent test. Upon any showing of non-compliance with emissions limitations or testing that indicates that emissions are within 10% of the emission limitations, the testing frequency shall revert to quarterly. Reduced testing frequency does not apply to engines with catalytic converters or oxidation catalyst. [OAC 252:100-8-6 (a)(3)(A)]

f. When periodic compliance testing shows engine exhaust emissions in excess of the lb/hr limits, the permittee shall comply with the provisions of OAC 252:100-9.

[OAC 252:100-9]

g. The owner/operator (O/O) shall comply with the Standards of Performance for Stationary Spark Ignition Internal Combustion Engine (SI-ICE), NSPS Subpart JJJJ, for all affected emission units, including but not limited to the following: [40 CFR §§ 60.4230-60.4248]

Emission Standards for O/O

i. § 60.4233 What emission standards must I meet if I am an O/O of a stationary SI-ICE?

ii. § 60.4234 How long must I meet the emission standards if I am an O/O of a stationary SI-ICE?

Other Requirements for O/O

iii. § 60.4236 What is the deadline for importing or installing stationary SI ICE produced in the previous model year?

iv. § 60.4237 What are the monitoring requirements if I am an O/O of an emergency stationary SI-ICE?

Compliance Requirements for O/O

v. § 60.4243 What are my compliance requirements if I am an O/O of a stationary SI-ICE?

Testing Requirements for O/O

vi. § 60.4244 What test methods and other procedures must I use if I am an O/O of a stationary SI-ICE?

Notification, Reports, and Records for O/O

vii. § 60.4245 What are my notification, reporting, and recordkeeping requirements if I am an O/O of a stationary SI-ICE?

General Provisions

viii. § 60.4246 What parts of the General Provisions apply to me?

EUG D. Natural Gas-Fired Heaters: Emission limits have been established for NO_X and CO for EU H-2 through H-5 and include startup, shutdown, and maintenance (SSM). All other emissions were based on the heat input rating, AP-42 (7/98), Section 1.4, and a fuel sulfur content of 4 ppmv (0.000675 lb/MMBTU). Emissions limits for EU H-2 through H-5:

				NO_x		CO	
EU	**Point**	**Description**	**MMBTUH**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
H-2	H-2	Regeneration Heater	5.605	0.27 [1]	1.19	0.51 [1]	2.21
H-3	H-3	Hot Oil Heater	17.4	0.83 [1]	3.65	1.56 [1]	6.82
H-4	H-4	Regeneration Heater	5.605	0.27 [1]	1.19	0.51 [1]	2.21
H-5	H-5	Hot Oil Heater	17.4	0.83 [1]	3.65	1.56 [1]	6.82

[1] Three-hour average. These limits represent BACT for these units.

a. The heaters (EU H-2 through H-5) shall only be fired with natural gas having a maximum sulfur content of 0.25 grains or less of total sulfur (as hydrogen sulfide) per 100 standard cubic feet (< 4 ppmv). Compliance can be shown by the following methods: for gaseous fuel, a current gas company bill, lab analysis, stain-tube analysis, gas contract, tariff sheet, or other approved methods. Compliance shall be demonstrated at least once every calendar year.

b. The owner/operator (O/O) shall comply with the Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, NSPS Subpart Dc, for all affected emission units, including but not limited to the reporting and recordkeeping requirements (§ 60.48c), demonstrating that the units combust only natural gas containing 0.25 grains or less of total sulfur (as hydrogen sulfide) per 100 standard cubic feet (< 4 ppmv). [40 CFR §§ 60.40c-60.48c]

c. The heaters (EU H-2 through H-5) shall be equipped with Low-NO_X burners. [OAC 252:100-8-6(a)(1)]

EUG E. Condensate Tanks: Emissions from condensate production will be controlled through the use of a condensate stabilizer.

EU	Point	Contents	Barrels	Gallons
TK-3	TK-3	Condensate	1,000	42,000
TK-4	TK-4	Condensate	1,000	42,000
TK-5	TK-5	Condensate	1,000	42,000
TK-6	TK-6	Condensate	1,000	42,000

a. The produced liquids from the inlet separator shall be treated by a condensate stabilizer prior to being stored in the atmospheric storage tanks. The off-gases from the stabilizer shall be recycled/recompressed into the inlet manifold of the gas plant.

b. Working and breathing emissions from the condensate tanks (EU TK-3 through TK-6) shall be controlled by a flare with controlled emissions from the tanks limited to a maximum rate of 0.82 TPY based on a maximum condensate throughput of 9,198,000 gallons per year. This limit represents BACT and includes startup, shutdown, and maintenance (SSM). All vessel gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

c. Tanks TK-3 through TK-6 are subject to federal New Source Performance Standards (NSPS), 40 CFR Part 60, Subpart Kb, and shall comply with all applicable standards including but not limited to:

i. §60.110b Applicability and designation of affected facility.
ii. §60.111b Definitions.
iii. §60.112b Standard for volatile organic compounds (VOC).
iv. §60.113b Testing and procedures.
v. §60.115b Reporting and recordkeeping requirements.
vi. §60.116b Monitoring of operations.

EUG F. Produced Water Tanks: Emissions from the Produced Water Tanks were estimated based on an average factor of $1.1 \bullet 10^{-5}$ tons of VOC emitted per barrel of produced water and 20 barrels per day (BPD) of produced water throughput (all four tanks combined). Emissions from the Produced Water Tanks are considered to be an Insignificant Activity.

EU	Point	Contents	Barrels	Gallons
WTK-1	WTK-1	Produced Water	400	16,800
WTK-2	WTK-2	Produced Water	400	16,800
WTK-3	WTK-3	Produced Water	400	16,800
WTK-4	WTK-4	Produced Water	400	16,800

a. The permittee shall keep records of the amount of liquids processed through EUG F and compute VOC emissions on a monthly basis (monthly and 12-month rolling totals).

b. Emissions from the produced water tanks (EU WTK-1 through WTK-4) shall be controlled by a flare with controlled emissions from the tanks limited to a maximum rate of 0.02 TPY based on a maximum produced water throughput of 20 barrels per day. This limit represents BACT. All vessel gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

EUG G. Condensate Truck Loading: Emissions from loading condensate into tank trucks were estimated based on AP-42 (1/95), Section 5.2, a throughput of 4,599,000 gallons per year (for each separate process train, CL-1 and CL-2), and a computed emission factor of 5.11 pounds per 1000 gallons loaded. Emissions from condensate loading operations are controlled by an enclosed flare. These limits include startup, shutdown, and maintenance (SSM).

				VOC
EU	**Point**	**Name**	**Throughput**	**TPY**
CL-1	CL-1	Condensate Truck Loading	4,599,000 gallons/year	3.53
CL-2	CL-2	Condensate Truck Loading	4,599,000 gallons/year	3.53

a. Total facility-wide condensate throughput shall not exceed 9,198,000 gallons in any 12-month period. The permittee shall monitor and record the condensate throughput each month and compute VOC emissions (monthly and 12-month rolling totals).

b. Emissions associated with condensate loading shall be controlled by an enclosed flare.

EUG H. Produced Water Truck Loading: Emission from loading produced water into tank trucks were estimated based on AP-42 (1/95), Section 5.2, a throughput of 153,000 gallons per year (for each separate process train, WL-1 and WL-2), and a computed emission factor of 0.08 pounds per 1000 gallons. Emissions from the Produced Water Tanks are considered to be a Trivial Activity.

EU	Point	Name	Throughput
WL-1	WL-1	Produced Water Truck Loading	153,000 gallons/year
WL-2	WL-2	Produced Water Truck Loading	153,000 gallons/year

EUG I. Process Flare: This emission unit group has been deleted. The equipment formerly included in this EUG is included in a separate permit.

EUG J. Amine Units: Emissions from the amine units were estimated based on the results of a process simulation performed using ProMax, a throughput of 20,000 barrels of NGL per day (for each separate process train, AMINE-1 and AMINE-2), an amine recirculation rate of 90 gallons per minute, an inlet pressure of 650 psig, and an inlet temperature of 85^{o}F. Flash gases are routed to the hot oil heaters or the amine reboilers (95% control efficiency) and the regeneration unit still vent emissions will be exhausted to the atmosphere. These limits include startup, shutdown, and maintenance (SSM).

				VOC	**H_2S**
EU	**Point**	**Name**	**NGL Throughput**	**TPY**	**lb/hr**
AMINE-1	AMINE-1	Amine Unit Still Vent	20,000 bbl/day	5.59	0.3
	H-3	Flash Tank Emissions		1.80	--
AMINE-2	AMINE-2	Amine Unit Still Vent	20,000 bbl/day	5.59	0.3
	H-4	Flash Tank Emissions		1.80	--

a. The permittee shall analyze the H_2S concentration of each still vent exhaust using an online monitor (or other method approved by the DEQ) at least once per calendar week. The maximum permitted still vent exhaust gas H_2S concentration shall be 245 ppmv. If the still vent exhaust gas H_2S concentration from each test is less than 200 ppmv for four consecutive weeks, the testing frequency may be reduced to one test for each still vent exhaust per calendar month. If the result of any monthly test exceeds 200 ppmv, test frequency shall revert to once per calendar week. In lieu of testing the still vent exhaust gas emissions, the permittee may elect to test the H_2S concentration of the inlet gas (arriving at the facility from each individual point of ingress or at a common header or headers) at least once each calendar week using a “stain tube” analysis with a first scale mark no larger than 0.2 ppmv and a maximum measurement concentration of 15 ppmv or less. The maximum permitted inlet gas H_2S concentration shall be 0.41 ppmv. If an equivalent method is used, it must satisfy the same requirements for scale and maximum concentration and it must be approved in advance by the DEQ. If the inlet gas H_2S concentration from each test is less than 0.2 ppmv for four consecutive weeks, the testing frequency may be reduced to one test per calendar month. If the result of any monthly test exceeds 0.2 ppmv, test frequency shall revert to once per calendar week. [OAC 252:100-31]

b. Each amine unit will be exempt from NSPS, Subpart OOOO as long as it is used to process liquids derived from inlet gas with a concentration of 4.0 ppmv H_2S or less. [OAC 252:100-31]

c. For each amine unit, the rate of natural gas liquids treatment shall not exceed 20,000 barrels per day, averaged monthly. For each amine unit, the amine recirculation rate shall not exceed 90 gallons per minute. [OAC 252:100-31]

d. Gases evolved from the flash tank of each amine unit shall be routed to a hot oil heater, a regeneration heater, to another heater, or to a flare.

e. The permittee shall keep records of the amount of natural gas liquids processed through each amine unit on a daily basis and shall compute average daily throughput at least once per calendar month. The permittee shall record the amine recirculation rate at least once per calendar week unless the pump has a maximum rate of 90 gallons per minute (or lower).

EUG K. Emergency Flares and Enclosed Flare: Emissions were estimated based on the heat input rating, AP-42 (1/95), Section 13.5, an estimated amount of waste gas and heat content. Emissions from EU FLARE2, FLARE3, and EFL-1 represent insignificant activities.

EU	Point	Emission Unit
FLARE2	FLARE2	Emergency Flare from Process Train 1
FLARE3	FLARE3	Emergency Flare from Process Train 2
EFL-1	EFL-1	Enclosed Flare for Condensate Tanks, Condensate Tank Loading, and Produced Water Tanks

a. The emergency flares (FLARE2 and FLARE3) shall comply with the NSPS, Subpart A General Provisions for control devices and shall be designed and operated in accordance with the requirements of 40 CFR Part 60, Paragraph 60.18.

b. Records of emergency flare pilot flame(s) outages shall be maintained along with the time and duration of all periods during which the pilot flame is/are absent.

c. The enclosed flare (EFL-1) shall be operated and maintained to be smokeless with no visible emissions except for periods not to exceed a total of five minutes during any two consecutive hours as determined by 40 CFR Part 60, Appendix A, Method 22. Within 180 days of commencement of operation of the enclosed flare, the permittee shall perform a visual determination of smoke emissions from the enclosed flare using Method 22.

d. The feed system to the enclosed flare shall be equipped with a pressure sensor and the pressure sensor shall be maintained at all times to detect the need for a flame. A device to monitor the flare for the presence of a flame shall be in operation at all times that the pressure sensor detects a need for a flame. Records shall be kept of all periods that a flame is not present when required and of all periods when the pressure sensor and/or the igniter is not operating properly. The records shall contain a description of the reason(s) for absence of the flame and/or the problem(s) with the pressure sensor and/or igniter as well as the steps taken to return the flame, pressure sensor, and igniter to proper operation.

EUG L. Fugitives: Emissions from the fugitive equipment leaks are based on equipment type, the number of components and the average emission factors for oil and gas facilities. There are no emission limits applied to these EU but they are required to meet certain work practice standards.

EU	Point	Number	Type	Service
FUG	FUG	616	Valves	Gas
		14	Relief Valves	Gas
		10	Compressor Seals	Gas
		1,232	Flanges	Gas
		400	Valves	Light Oil
		800	Flanges	Light Oil
		8	Pump Seals	Light Oil
FUG2	FUG2	616	Valves	Gas
		14	Relief Valves	Gas

EU	Point	Number	Type	Service
		10	Compressor Seals	Gas
		1,232	Flanges	Gas
		400	Valves	Light Oil
		800	Flanges	Light Oil
		8	Pump Seals	Light Oil

a. The owner/operator shall implement a leak detection and repair (LDAR) program which meets or exceeds the standards of care incorporated in the following provisions of 40 CFR: the leak standards presented in § 60.5400, but possibly including exceptions outlined in § 60.5401 and alternative emission limitations in § 60.5402, the initial compliance demonstrations presented in §§ 60.5410-60.5412, the continuous compliance demonstrations presented in § 60.5415, and the notification, reporting, and recordkeeping requirements presented in §§ 60.5420-60.5422. This LDAR program shall cover all fugitive emissions sources (including each pump, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector) in VOC service. This requirement represents BACT.

b. The owner/operator shall implement a VOC reduction program which meets or exceeds the standards presented in 40 CFR § 60.5380 for centrifugal compressors and 40 CFR § 60.5385 for reciprocating compressors. This VOC reduction program shall cover all centrifugal and reciprocating compressors. This requirement represents BACT.

EUG M. Blowdowns: Emissions from the blowdowns are based on an estimated volume of gas which would be released, a molar conversion rate of 379.4 scf/lb-mol, and an extended gas analysis.

EU	Point	Name	Throughput
BD	BD	Engine Blowdowns	5,853,096 scf/yr
BD2	BD2	Turbine Blowdowns	1,618,984 scf/yr

c. Blowdowns shall not exceed 7,472,080 scf in any 12-month period.

d. The permittee shall record the date and approximate time of each blowdown event and estimate and record the amount of gases released during each blowdown event. The permittee shall use these records to calculate monthly and 12-month rolling totals.

2. The permittee shall be authorized to operate this facility continuously (24 hours per day, every day of the year). [OAC 252:100-8-6(a)]

3. Replacement (including temporary periods of 6 months or less for maintenance purposes), of internal combustion engine(s)/turbine(s) with emissions limitations specified in this permit with engine(s)/turbine(s) of lesser or equal emissions of each pollutant (in lbs/hr and TPY) are authorized under the following conditions. [OAC 252:100-8-6(f)(2)]

a. The permittee shall notify AQD in writing not later than 7 days prior to start-up of the replacement engine(s)/turbine(s). Said notice shall identify the old engine/turbine and shall include the new engine/turbine make and model, serial number, horsepower rating, and pollutant emission rates (g/hp-hr, lb/hr, and TPY) at maximum horsepower for the altitude/location.

b. Quarterly emissions tests for the replacement engine(s)/turbine(s) shall be conducted to confirm continued compliance with NO_X and CO emission limitations. A copy of the first quarter testing shall be provided to AQD within 60 days of start-up of each replacement engine/turbine. The test report shall include the engine/turbine fuel usage, stack flow (ACFM), stack temperature (°F), and pollutant emission rates (g/hp-hr, lbs/hr, and TPY) at maximum rated horsepower for the altitude/location.

c. Replacement equipment and emissions are limited to equipment and emissions which are not a modification under NSPS or NESHAP, or a significant modification under PSD. For existing PSD facilities, the permittee shall calculate the PTE or the net emissions increase resulting from the replacement to document that it does not exceed significance levels and submit the results with the notice required by paragraph a of this Specific Condition.

d. Engines installed as allowed under the replacement allowances in this Specific Condition that are subject to 40 CFR Part 63, Subpart ZZZZ and/or 40 CFR Part 60, Subpart JJJJ shall comply with all applicable requirements.

e. Turbines installed as allowed under the replacement allowances in this Specific Condition that are subject to 40 CFR Part 60, Subpart KKKK shall comply with all applicable requirements.

4. The permitte shall abide by all applicable requirements of NESHAP, 40 CFR Part 63, Subpart ZZZZ affecting any of the engines subject to these requirements, including, but not limited to, the following. [40 CFR 63.6585 through 63.6675]

a. § 63.6585 Am I subject to this subpart?
b. § 63.6590 What parts of my plant does this subpart cover?
c. § 63.6595 When do I have to comply with this subpart?
d. § 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?
e. § 63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?
f. § 63.6605 What are my general requirements for complying with this subpart?
g. § 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?
h. § 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?
i. § 63.6615 When must I conduct subsequent performance tests?
j. § 63.6620 What performance tests and other procedures must I use?
k. § 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

l. § 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?
m. § 63.6635 How do I monitor and collect data to demonstrate continuous compliance?
n. § 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?
o. § 63.6645 What notifications must I submit and when?
p. § 63.6650 What reports must I submit and when?
q. § 63.6655 What records must I keep?
r. § 63.6660 In what form and how long must I keep my records?
s. § 63.6665 What parts of the General Provisions apply to me?
t. § 63.6675 What definitions apply to this subpart?

5. The permittee shall comply with NSPS, Subpart OOOO, Standards of Performance for Crude Oil and Natural Gas Production, Transportation, and Distribution, for all affected facility located at this facility. [40 CFR 60.5360 to 60.5430]

a. § 60.5360 What is the purpose of this subpart?
b. § 60.5365 Am I subject to this subpart?
c. § 60.5370 When must I comply with this subpart?
d. § 60.5375 What standards apply to gas well affected facilities?
e. § 60.5380 What standards apply to centrifugal compressor affected facilities?
f. § 60.5385 What standards apply to reciprocating compressor affected facilities?
g. § 60.5390 What standards apply to pneumatic controller affected facilities?
h. § 60.5395 What standards apply to storage vessel affected facilities?
i. § 60.5400 What equipment leak standards apply to affected facilities at an onshore natural gas processing plant?
j. § 60.5401 What are the exceptions to the equipment leak standards for affected facilities at onshore natural gas processing plants?
k. § 60.5402 What are the alternative emission limitations for equipment leaks from onshore natural gas processing plants?
l. § 60.5405 What standards apply to sweetening units at onshore natural gas processing plants?
m. § 60.5406 What test methods and procedures must I use for my sweetening units affected facilities at onshore natural gas processing plants?
n. § 60.5407 What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?
o. § 60.5408 What is an optional procedure for measuring hydrogen sulfide in acid gas-Tutwiler Procedure?
p. § 60.5410 How do I demonstrate initial compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?

q. § 60.5411 What additional requirements must I meet to determine initial compliance for my closed vent systems routing emissions from storage vessels or centrifugal compressor wet seal fluid degassing systems?
r. § 60.5412 What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my storage vessel or centrifugal compressor affected facility?
s. § 60.5413 What are the performance testing procedures for control devices used to demonstrate compliance at my storage vessel or centrifugal compressor affected facility?
t. § 60.5415 How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?
u. § 60.5416 What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my storage vessel or centrifugal compressor affected facility?
v. § 60.5417 What are the continuous control device monitoring requirements for my storage vessel or centrifugal compressor affected facility?
w. § 60.5420 What are my notification, reporting, and recordkeeping requirements?
x. § 60.5421 What are my additional recordkeeping requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?
y. § 60.5422 What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?
z. § 60.5423 What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?
aa. § 60.5425 What parts of the General Provisions apply to me?
bb. § 60.5430 What definitions apply to this subpart?

6. The following records shall be maintained on-site to verify Insignificant Activities. No recordkeeping is required for those operations that qualify as Trivial Activities.

[OAC 252:100-8-6 (a)(3)(B)]

a. For fluid storage tanks with a capacity of less than 39,894 gallons and a true vapor pressure less than 1.5 psia: records of capacity of the tanks and contents.
b. For activities that have the potential to emit less than 5 TPY (actual) of any criteria pollutant (for example, VOC emissions from the produced water tanks): the type of activity and the amount of emissions from that activity (annual).

7. The permittee shall maintain records of operations as listed below. These records shall be maintained on-site or at a local field office for at least five years after the date of recording and shall be provided to regulatory personnel upon request. [OAC 252:100-8-6 (a)(3)(B)]

a. Periodic emission testing for the engines and each replacement engine.
b. Operating hours for the engines if less than 220 hours per quarter and not tested.
c. O&M records for an engine if not tested in each 6-month period.
d. Emissions monitoring data for the turbines and each replacement turbine.
e. Combustion fuel sulfur test/analysis records as required by Specific Condition 1.

f. Records of blowdown events including estimates of blowdown volumes (monthly and 12-month rolling totals).
g. Records of emergency flare pilot flame outages.
h. Records of flame outages during events where material is directed to the enclosed flare and time periods where the pressure sensor and/or igniter is not operating properly.
i. Records required by NSPS, Subparts A, Dc, Kb, JJJJ, KKKK, and OOOO.
j. Records required by NESHAP, Subpart ZZZZ.
k. Flow rate of the materials processed in the amine units (monthly averages).
l. Amine unit VOC emissions estimates (monthly and 12-month rolling totals).
m. Amine unit H_2S emissions compliance demonstration records as required by Specific Condition 1, EUG J (weekly and/or monthly as appropriate).
n. Condensate throughput and VOC emissions associated with truck loading emissions (monthly and 12-month rolling totals).
o. Records of VOC emissions when any flare is out of service (monthly and 12-month rolling totals).

8. The permittee shall submit an application for a Part 70 operating permit within 180 days of commencement of operation of any emission source whose construction has been authorized by this permit. The permittee shall also include in the application testing for the engines/turbines showing compliance with the applicable emission limitations in accordance with NSPS, Subparts JJJJ and KKKK. The permittee shall also determine the NO_2/NO_X in-stack ratio for the engines and the turbines during the applicable NSPS testing. In addition, the permittee shall provide the following:

a. An updated inlet gas analysis (extended analysis), identifying the inlet H_2S concentration.
b. Updated emissions estimates for the amine unit based on a new model run (either Amine-Calc, a process simulator, or another method approved by AQD) and using the updated gas analysis.
c. Results of the visual determination of smoke emissions (Method 22) from the enclosed flare.

9. If the NO_2/NO_X in-stack ratios determined during stack testing exceed the values used in the NO_2 compliance modeling (0.35 for the 4SLB engines and 0.20 for the turbines), the applicant shall remodel using the values derived from the stack tests. If the remodeling demonstrates that the facility contributes in a non-negligible way to any modeled NO_2 exceedance, the permittee shall be considered to be in violation of this permit. If the remodeling demonstrates that the facility contributes in a non-negligible way to any modeled NO_2 exceedance, the permittee shall comply with the provisions of OAC 252:100-9 and this permit must be re-opened to address this issue.

10. In addition to the testing required by NSPS, Subpart KKKK, the permittee shall conduct initial compliance testing for emissions of CO, $PM_{2.5}$, VOC, and formaldehyde on the new turbines (T-1 and T-2) at the 60% and 100% operating rates. Performance testing shall be conducted while the new units are operating within 10% of the desired operating rates. A written testing protocol shall be submitted to the AQD for review and approval at least 30 days prior to the start of such testing. The protocol shall describe how the testing will be performed.

The following USEPA methods shall be used for testing of emissions, unless otherwise approved by Air Quality:

Method 1:	Sample and Velocity Traverses for Stationary Sources.
Method 2:	Determination of Stack Gas Velocity and Volumetric Flow Rate.
Method 3:	Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.
Method 4:	Determination of Moisture in Stack Gases.
Method 5:	Determination of Particulate Emissions from stationary sources.
Method 10:	Determination of Carbon Monoxide Emissions from Stationary Sources.
Method 25/25A:	Determination of Non-Methane Organic Emissions From Stationary Sources.
Method 201A:	Determination of $PM_{2.5}$ Emissions
Method 202:	Condensable Particulate Matter
Method 320:	Vapor Phase Organic & Inorganic Emissions by Extractive FTIR

11. Within 30 days of commencement of construction of the Rose Valley Plant, the permittee shall submit a letter (certified mail, return receipt requested) to the Responsible Official (R.O.) for the Hopeton Plant, satisfying the following requirements:

a. The letter shall inform the R.O. of the Hopeton Plant that the owner/operator of the Hopeton Plant is required to submit an application to modify the current operating permit to incorporate any new applicable requirements (i.e., Title V requirements) that will result from construction of the Rose Valley Plant.
b. The permittee shall submit a copy of this letter to the Permitting Group of the Air Quality Division of the Oklahoma DEQ.

MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(July 21, 2009)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with the federal Clean Air Act (42 U.S.C. 7401, et al.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.
[40 C.F.R. §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations. [OAC 252:100-8-6(a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from an emergency and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV (Emergencies). [OAC 252:100-8-6(a)(3)(C)(iii)(I) & (II)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements.
[OAC 252:100-8-6(a)(3)(C)(iv)]

C. Every written report submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), OAC 252:100-8-6(c)(1), and OAC 252:100-8-6(c)(2)(B)]

B. Records of required monitoring shall include:

(1)the date, place and time of sampling or measurement;
(2)the date or dates analyses were performed;
(3)the company or entity which performed the analyses;
(4)the analytical techniques or methods used;
(5)the results of such analyses; and
(6)the operating conditions existing at the time of sampling or measurement.

[OAC 252:100-8-6(a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. Submission of these periodic reports will satisfy any reporting requirement of Paragraph E below that is duplicative of the periodic reports, if so noted on the submitted report. [OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions. [OAC 252:100-8-6(a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act. [OAC 252:100-43]

F. Any Annual Certification of Compliance, Semi Annual Monitoring and Deviation Report, Excess Emission Report, and Annual Emission Inventory submitted in accordance with this permit shall be certified by a responsible official. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1), OAC 252:100-9-7(e), and OAC 252:100-5-2.1(f)]

G. Any owner or operator subject to the provisions of New Source Performance Standards ("NSPS") under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants ("NESHAPs") under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.

[40 C.F.R. §§60.7 and 63.10, 40 CFR Parts 61, Subpart A, and OAC 252:100, Appendix Q]

H. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted. [OAC 252:100-8-6(c)(4)]

I. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality.

[OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

J. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter (PM_{10}). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

K. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 C.F.R. Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-8-6(c)(1) and OAC 252:100, Appendix Q]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit.

[OAC 252:100-8-6(c)(5)(A), and (D)]

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.
[OAC 252:100-8-6(c)(5)(C)(i)-(v)]

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." [OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.
[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification. [OAC 252:100-8-6(c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit. [OAC 252:100-8-6(d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit. [OAC 252:100-8-6(d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.
[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6(a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1(d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.
[OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege.
[OAC 252:100-8-6(a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6(c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking, reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit.

[OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.

[OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer.

[Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.

[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances: [OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

(1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
(2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
(3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.
(4) DEQ determines that the permit should be amended under the discretionary reopening provisions of OAC 252:100-8-7.3(b).

C. The permit may be reopened for cause by EPA, pursuant to the provisions of OAC 100-8-7.3(d). [OAC 100-8-7.3(d)]

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a “grandfathered source,” as defined under AQD rules. Such changes may require a permit modification.

[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6(c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(18) for confidential information submitted to or obtained by the DEQ under this section):

(1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
(2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
(3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
(4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.

[OAC 252:100-8-6(c)(2)]

SECTION XIV. EMERGENCIES

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.

[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (IV)]

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance. [OAC 252:100-8-6(a)(3)(C)(iii)(II)]

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [OAC 252:100-8-2]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that: [OAC 252:100-8-6 (e)(2)]

(1) an emergency occurred and the permittee can identify the cause or causes of the emergency;
(2) the permitted facility was at the time being properly operated;
(3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit.

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6(e)(3)]

F. Every written report or document submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6(a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or Federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list.

(1) 5 tons per year of any one criteria pollutant.
(2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.

[OAC 252:100-8-2 and OAC 252:100, Appendix I]

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or Federal applicable requirement applies is not trivial even if included on the trivial activities list.
[OAC 252:100-8-2 and OAC 252:100, Appendix J]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6(a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

(1) result in no net emissions increases,
(2) are not modifications under any provision of Title I of the federal Clean Air Act, and
(3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of seven (7) days, or twenty four (24) hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this paragraph. [OAC 252:100-8-6(f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

(1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter. [OAC 252:100-13]
(2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]
(3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]
    (a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
    (b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
    (c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
    (d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and

the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.

(4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

(5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]

(6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]

(7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances: [40 CFR 82, Subpart A]

(1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;

(2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and

(3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term “motor vehicle” as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term “MVAC” as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B: [40 CFR 82, Subpart F]

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;

(2) Equipment used during the maintenance, service, repair, or disposal of appliances must

comply with the standards for recycling and recovery equipment pursuant to § 82.158;

(3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161;

(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;

(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and

(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Source's Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in OAC 252:100-8-7.2(a) only if the following procedures are followed:

(1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.

(2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).

(3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).

(4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R.§ 70.8(a) and (c).

(5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.

(6) The DEQ complies with 40 C.F.R. § 70.8(d).

(7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).

(8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.

(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ

as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).

(10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[OAC 252:100-43-6]

PART 70 PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 NORTH ROBINSON, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit No. 2012-1393-C PSD

Mid-America Midstream Gas Services, L.L.C.,

having complied with the requirements of the law, is hereby granted permission to construct the Rose Valley Plant, located in Section 6, T25N, R14W, in Woods County, Oklahoma, subject to Specific Conditions and Standard Conditions dated July 21, 2009, both of which are attached.

In the absence of construction commencement, this permit shall expire 18 months from the issuance date, except as authorized under Section VIII of the Standard Conditions.

______________________________ ______________________

Division Director **Date**

Air Quality Division

DEQ Form #100-890

Ms. Kristin Ikard
Corporate Air Coordinator – Midstream
Mid-America Midstream Gas Services, L.L.C.
P.O. Box 18955
Oklahoma City, OK 73154-0955

SUBJECT: Title V Construction Permit No. **2012-1393-C PSD**
Rose Valley Plant
Section 6, Township 25N, Range 14W
Woods County, Oklahoma

Dear Ms. Ikard:

Enclosed is the permit authorizing construction of the referenced facility. Please note that this permit is issued subject to standard and specific conditions, which are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

Also note that you are required to annually submit an emission inventory for this facility. An emission inventory must be completed on approved AQD forms and submitted (hardcopy or electronically) by April 1st of every year. Any questions concerning the form or submittal process should be referred to the Emission Inventory Staff at 405-702-4100.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me or Tom Richardson, the permit writer, at (405) 702-4100.

Sincerely,

Phillip Fielder, P.E.
Permits & Engineering Group Manager
AIR QUALITY DIVISION

Enclosure